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(d) To correlate study and research on corrosion problems among technical associations to reduce duplication and increase efficiency.

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Corrosion on New Distillation Unit
Processing Low Sulfur Crude*

By D. L. BURNS

Abstract

This paper presents the case history of corrosion experienced on a new atmospheric and vacuum crude distillation unit. The crude charged was a low sulfur type, averaging 0.20% sulfur content, which is produced in West Texas, mostly from Ellenburger formations, of Ordovician age. Some test data for this crude, which are applicable to the corrosion problems, are tabulated for comparative purposes with like data for other crudes. A simplified flow diagram of the unit shows temperature and pressure conditions. The materials used in the various items of equipment are given.

Most affected by corrosion were the atmospheric tower overhead condenser shells and the carbon steel tubes in the radiant section of the fired heater where desalted crude is heated to 600° F. The paper deals principally with the nature of the corrosion in the furnace tubes, the factors entering into the problem and remedial measures used. Ammonia injection was used in neutralizing the corrosive elements present in the atmospheric tower overhead steam and 7% chromium-0.5% molybdenum alloy steel tubes were substituted for carbon steel in the radiant section of the furnace. Corrosion rates for the carbon steel heater tubes are plotted vs. temperature and compared to those experienced when processing West Texas crude containing 1.5% sulfur. The marked effects which the tube wall temperatures have on the corrosion rates are discussed. A peculiar feature about this corrosion experience is that the same crude which gave trouble on the new unit had been processed previously in an older, though similar, unit for approximately three years without corrosion difficulties. A comparison between operating data for the two units is made.

WITHIN THE REFINERIES of the petroleum industry, where a full line of products are manufactured, a wide variety of corrosion problems exists due to the many processes which are involved. Discussions of problems pertaining to special processes such as solvent extraction or treating might interest some; but the distillation of crude is one process which is fundamental to the industry as a whole, so a history of unusual corrosion which was experienced in a new crude distillation unit should be of wider interest.

Crude oils, differing in composition, are run in a variety of equipment under various operating conditions, thus adding to the complexity of corrosion problems and the difficulty of proper correlation of information on corrosion. Many excellent papers have been presented on the general subject of the corrosive agents contained in various crudes, and have been of much value to corrosion engineers. There are others, presenting case histories of the corrosion experienced in specific process equipment with a

ABOUT THE AUTHOR—D. L. Burns, inspection and Corrosion Engineer at Gulf Oil Corporation's Port Arthur Refinery, received his BS from the University of Chicago in 1923. He was engaged in highway and bridge contracting and construction in Texas from 1923 to 1929. In that year he was employed by Gulf to design and construct vessels. For the past 18 years he has been occupied with general inspection of refinery process equipment and mitigation of corrosion therein. He is vice-chairman of Sabine-Neches Section NACE.

given charge, which have added much to the store of knowledge on the subject.

Each experience with a new unit, or with a new type crude charge to an older unit, involves the testing of the corrosion resistance of the materials of construction in that unit on a full scale; and information of interest to the entire industry is thereby developed. It is with these considerations in mind that a case history is presented covering the corrosion experienced in a new atmospheric and vacuum crude distillation unit charging a desalted, low sulfur crude, at the Port Arthur Refinery of Gulf Oil Corporation.

For many years the question of the extent of the corrosion which might be expected in new equipment when processing certain crudes has concerned the engineers and chemists of the petroleum industry. It is generally agreed that the *high* sulfur crudes or fractions therefrom are very corrosive to iron and steel at elevated temperatures, and severe corrosion is variously reported to start at 500° F.[1] to 700° F.[2] However, many experienced engineers and investigators have realized that the percentage of sulfur in a crude is not necessarily a direct measure of the tendency to corrode. This conclusion was reached by Mr. Arthur Marks as early as 1936. His conclusion was based on certain studies made by the American Petroleum Institute Committee on Corrosion of Refinery Equipment which were presented in Mr. Mark's report to the API at its annual meeting that year.[3] Mr. Gustav Egloff expressed this same view in 1937.[4] Nevertheless, it would have been considered most improbable heretofore that a desalted crude, having such a low sulfur content as 0.20 percent, could cause corrosion rates in distillation equipment comparable to those previously experienced only when handling high sulfur crudes. Yet, such was the severity of the corrosion experienced in the new unit which started operations in May, 1948.

The parts of the unit which corroded most rapidly were the atmospheric tower overhead condenser shells and the carbon steel tubes in the radiant section of the furnace through which the desalted crude passed. The condenser corrosion was not so unusual; but the high rate of attack on the carbon steel tubes was considered exceptional for such a low sulfur crude. Consequently, the greater part of this paper will deal with the nature of the corrosion in the furnace tubes, the factors entering into the problem, the measures taken to remedy the trouble, and the results obtained from these measures as disclosed by recent inspections.

A peculiar feature of this corrosion was that the same crude had been processed previously on a similar unit for about three years without corrosion difficulties. Therefore, based on that experience, corrosion rates on carbon steel heater tubes, towers, and exchanger shells of the new unit should not have been severe.

The Crude

The crude charged to the unit is produced in West Texas, mostly from Ellenburger formations, of Ordovician geological age, and for simplification in this paper will be referred to as "Ordovician" crude. It is a paraffin base crude, having a low salt content and negligible concentrations of acidic materials. It could have been considered sweet, if classified by the sulfur content which averaged 0.20 percent; yet, due to the fact that appreciable quantities of hydrogen sulfide and mercaptan sulfur were present in the lighter fractions, it was suspected of being potentially corrosive.

Some routine tests of this crude are given in Table 1. They are compared to like tests on an East Texas crude, unquestionably sweet, and those on a West Texas crude, unquestionably sour. It has been noted that many sulfur compounds have a tendency to de-

compose during distillation and form hydrogen sulfide and mercaptans which are known to be corrosive at elevated temperatures.[5] Also, the sulfur compounds in different crudes may vary appreciably in this tendency. Therefore, for comparative purposes, some tests on the sulfur in the lighter fractions from these crudes have been included in this table for their possible value in indicating the amount and type of sulfides which are evolved during distillation.

It may be seen that the quantities of sulfides in the lighter fractions from the "Ordovician" crude are intermediate between those occurring in like fractions from East Texas and West Texas crudes. The sulfur in the gasoline distillate from East Texas crude is negligible; whereas the percent of sulfur in such distillate from "Ordovician" is 0.13, and 0.26 in that from West Texas crude. It is proposed that such a tabulation of tests as shown in Table I would be helpful in a study of the corrosive tendencies of crudes. Of course, these comparisons are only indicative of what might be gained by further study along this line.

The salt content of the raw crude is quite low, averaging 11.6 lbs. per 1000 barrels expressed as sodium chloride; whereas the salt content of the desalted crude is approximately 2.5 lbs per 1000 barrels. The salts which remained in the desalted crude were tested to determine the relative amounts of sodium, calcium and magnesium chlorides present. The sodium chloride content was equal to 1.08 lbs. per 1000 barrels of desalted crude; calcium chloride, 0.62 lbs.; and the amount of magnesium present was so small that it was insufficient for accurate determination.

A test for acidity of the desalted crude was made and the neutralization number, as determined by ASTM Method D 664-46T, was nil. Sediment and water varied from a trace to 0.1 percent.

The Unit

A simplified flow diagram of the new unit is shown in Figure 1. The unit consists principally of: the conventional crude preheating exchangers having carbon steel shells and admiralty metal exchanger tubes; eight electrical desalting tanks and one surge drum; also, a combination furnace, one side for heating the desalted crude charged to the atmospheric fractionating tower and one for heating the reduced crude feed to the vacuum tower; an 11-foot diameter atmospheric tower; an 18-foot diameter vacuum tower; two stripping towers; one barometric condenser with vacuum jets and the necessary pumps, piping and product coolers.

The material used in the original construction of the unit was mostly carbon steel, although alloy material or alloy linings were employed to some extent where corrosion had been anticipated. For example, the furnace tubes and headers in the atmospheric heater and most of the process piping were carbon steel. The transfer line, 18-inch O.D., from the heater to the atmospheric tower was clad on the interior with stainless steel, Type 405. The atmospheric tower, 11 feet in diameter and 125 feet in height, was carbon steel with Meehanite trays and bubble caps. The vacuum heater was equipped with

TABLE I

Comparison of Test Data for Certain Crudes and Distillates

	"Ordovi-cian"	East Texas	West Texas
Crude:			
Gravity: °API	43.2	38.5	33.8
Sulfur: percent	0.20	0.30	1.49
Salt Content*	11.6	29.0	44.2
Salt Content†	2.5	2.0	3.9
Wet Gas: Vol. percent	1.0‡	2.5‡	1.7‡
Hydrogen Sulfide: Mol. percent	0.8	nil	20.2
Gasoline Fraction: Vol. percent	24.7	26.7	17.3
Sulfur: percent	0.13	0.02	0.26
Mercaptan Sulfur: percent	0.065	nil	0.090
Hydrogen Sulfide: percent	0.007	nil	0.070
Over Point: °F	102	106	110
End Point: °F	324	342	284
Naphtha Fraction: Vol. percent	5.3	4.4	14.1
Sulfur: percent	0.11	0.02	0.30
Mercaptan Sulfur: percent	0.05	......	0.10
Hydrogen Sulfide: percent	nil	......	nil
Over Point: °F	308	292	280
End Point: °F	375	397	402
Kerosene Fraction: Vol. percent	19.8	12.1	28.5§
Sulfur: percent	0.09		0.78§
Mercaptan Sulfur: percent	0.05		0.10§
Atmos. Tower Bottoms: Vol. percent	37.8	54.2	34.8
Sulfur: percent	0.31	0.38	1.88

Sulfur and sulfides are expressed as weight percent of the distillate under which they are reported.

* Average salt content expressed as lbs. of NaCl equivalent per 1,000 bbls. of raw crude.

† After electrical desalting, i.e., as charged to the stills.

‡ Varies appreciably from season to season due to changes in temperature of condenser water.

§ These tests are for a light fuel oil distillate.

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carbon steel tubes along the side wall of the radiant section, and 7 percent chromium-0.5 percent molybdenum alloy steel tubes at the outlet end of the coil. The headers on the furnace tubes were box type, same material as the tubes. The two 18-inch O.D. transfer lines to the vacuum tower were also alloy lined. The vacuum tower shell was constructed of carbon steel, clad on the inside with Type 405 stainless steel throughout the 18-foot diameter section and lower 8-foot diameter stripper section; but the top condensing section was plain steel. The trays and caps in the main section of this tower were 12 percent chromium steel, Type 410. The two stripper towers were unlined and had Meehanite trays and caps. All of the exchangers and product coolers had carbon steel shells, and all but three of them were equipped with admiralty metal exchanger tubes. The three exchangers which did not have admiralty tubes were in hot oil service and were equipped with 7 percent Cr-0.5 percent Mo alloy tubes. The run-down line from the atmospheric tower overhead condensers was fabricated of Monel metal and the receiving drum for this stream was lined with Gunite.

Some pertinent operating and test data are shown on the flow diagram, which are representative of normal operation. The raw crude charge is preheated to 200° F., then mixed with water at the same temperature and desalted. In passing, it might be noted that the pH of the water entering the crude stream was 7.6, while the effluent water from the electrical desalters was about 4.5 during the early stages of operation. Some minor corrosion of the internal water piping was noted, and sodium hydroxide solution equivalent to 2 lb. of NaOH per 1000 bbl. of crude charge was then injected into the crude to bring the pH of the water effluent to 7.0. Careful checking of the desalted crude was instituted to make sure that no caustic was carried into the still with the desalted crude, as it was believed that any free entrained caustic would attack carbon steel furnace tubes at elevated temperatures. No trace of caustic in the desalted crude has been observed.

The desalted crude is pumped through additional heat exchangers and the temperature of the oil is raised to 345° F at the inlet to the convection section of the atmospheric heater; the pressure is 210 psi. At the inlet to the radiant section, the temperature is 475° F; the oil outlet temperature is 605° F. Oil pressure at the outlet is not measured; but the pressure in the flash section of the atmospheric fractionating tower is 12 psi. Temperature in the flash zone of this tower is 585° F, and, at the top of the tower, 240° F. Process steam enters the tower below

Figure 1—Simplified flow diagram, new unit.

the flash section and at higher points where the vents from the strippers enter.

The overhead from the atmospheric tower, comprising approximately 25 percent of the crude as gasoline distillate plus the process steam, is condensed in six tubular condensers equipped with admiralty metal tubes. The vapors flow in parallel through three banks of condensers, two to the bank. Three side streams are taken from this tower to strippers. For the sulfur content on these various streams refer again to Table I.

The bottoms from the atmospheric tower, which comprise 37.8 percent of the charge, are stripped with superheated steam in the lower section of the tower. They are then charged to the radiant section of the vacuum tower feed heater, two-pass arrangement, and transferred to the vacuum tower through two 18-inch lines. The oil outlet temperature from the vacuum heater is 730° F. Superheated steam is introduced into the roof tubes of this heater. The temperature in the flash zone of the vacuum tower is 700° F, and the pressure is 4 inches of Hg absolute. The residual stock, 7.6 percent of the crude, has a sulfur content of 0.49 percent. This residuum and the various lube distillate side streams, after stripping with super-heated steam, exchange heat with the incoming desalted crude and are pumped to stock tanks.

Corrosion Experienced

It may be of interest to discuss the corrosion experienced on the unit in the order in which it appeared. The still was started May 8, 1948, charging the crude described earlier, and lined out very well

for a new unit. During the initial run, the water from the atmospheric tower overhead distillate receiving drum was found to vary from 3.5 to 4 pH and the iron content of the water was equal to about 30 lb. per day. The injection of anhydrous ammonia into the overhead stream was considered.

After operating smoothly for four months, it was shut down for cleaning and inspection. Several tube bundles were cleaned but no overhead bundles were pulled. The vapor line and the tubes and baffle plate of one top condenser bundle were inspected at vapor inlet and conditions at that point indicated little or no corrosion. As a matter of routine, all furnace heater tubes were cleaned and calipered and records were made of the inside diameter measurements in the roll and near each end of each tube. Minor wall losses, in the order of 0.01 to 0.03-inch for the 3240 hour initial run, were noted in the carbon steel tubes near the outlet of the atmospheric heater. Since the original wall thickness of these tubes was 0.375 inch, the probable life should have been around 18,000 hours, or a little over two years, for about 16 of the tubes near the outlet, and much longer for the other radiant tubes. The carbon steel headers were in excellent condition. No tubes in the convection section nor in the vacuum section of the furnace showed any appreciable loss.

All vessels were in good condition with the exception of the atmospheric tower where some corrosion was observed in the flash section, which appeared as fine ridges or roughness of the steel shell. This corrosion was discovered after the removal of a thin layer of soft coke-like deposit on the walls. Samples of the corrosion product were analyzed with the following results.

TABLE II—Analysis of Corrosion Product

SAMPLE: Scale from wall of flash section, atmospheric tower.
DATE OF SAMPLE: September 22, 1948.
ANALYSIS: Percent by weight of sample, as received.

Volatile and combustible matter	30.8
Ash	69.2
	100.0
Iron as Fe	38.5
Sulfur as S	20.7
Chlorides as Cl	0.7

The ratio of the iron to the sulfur indicates that the ash of the scale was principally iron sulfide as FeS. The corrosion in the furnace tubes and in the tower, though not yet serious, accounted for the above deposit. This analysis was valuable in revealing the element most responsible for the corrosion taking place.

The unit was headed up and started on the second run. After about three weeks of operation, a small leak occurred in the cast steel body of the regulator valve in the gasoline distillate reflux line to the top of the atmospheric tower. A few days later, a leak developed in the bottom of one of the condensers which condensed atmospheric tower overhead. This corrosion indicated that neutralization of the overhead stream was advisable, and the unit was shut down for a few hours to install a connection in the vapor line to permit injection of ammonia. The regulator valve body on the reflux line was changed, and temporary repairs were made to the condensers.

The carbon steel body of the regulator had been corroded-eroded on the down stream side of the valve throat, but the valve stem and seat, 18-8 alloy, were not attacked. The carbon steel pipe of the reflux line was in good condition, however. An 18-8 alloy valve body was installed at a later date, and subsequent inspections proved the material to be satisfactory for this service.

The unit went back on stream following this short shutdown, and ammonia was started into the overhead stream. The quantity injected was regulated by a 1/4-inch needle valve and the pressure drop across a small orifice, as measured by a simple manometer. A pressure regulator maintained 20 psi on the ammonia system ahead of the manometer. Control was based on the pH of the water effluent from the overhead receiving drum, as determined by a Hellige Comparator, and the pH was maintained in the range of 6.8 to 7.2. Under this condition, no appreciable corrosion took place in the condensing system. About 0.8 lb. of ammonia per 1000 barrels of crude charged was required to maintain this condition.

The unit completed the balance of the second scheduled run without further event, and the second turnaround occurred during February, 1949. At that time, all of the equipment on the unit was again carefully inspected.

The corrosion damage to the condenser shells, which had occurred prior to ammonia injection, was appraised. Severe pitting of the bottom portion of the three upper shells had caused the leak previously mentioned. This corrosion had been caused by the hydrogen sulfide, other sulfides, small quantities of chlorides and condensing steam which were present in the overhead stream. The small percentage of chlorides which was present undoubtedly had an accelerating influence on this corrosion prior to the injection of ammonia. Three new shells were ordered to be prepared, and the lower half of the new shells were lined with 5/64-inch Monel metal as an added precaution. The lower condenser shells of each bank were found to have lost only 0.09-inch wall thickness. The admiralty metal tubes of the top condenser bundles were moderately corroded on the vapor side near the area where the steel shells were attacked, but the steel baffles of the tube bundles were severely corroded.

The wall thickness of the atmospheric tower flash section was measured and had lost 0.04-inch in 6500 hours of operation. This is equivalent to a corrosion rate of 0.05-inch per year, compared to a reported rate of 0.07-inch per year wall loss in a bubble tower in West Texas sour crude service.[6] Consequently, recommendations were made to strip line the affected area of this tower with stainless steel, Type 410.

The fired heater tubes were again calipered near tube ends, and wall losses were found to be a little greater than previously noted. Wall losses for the 3000-hour run were from 0.04 to 0.06-inch. The appearance of the inside of the tubes was good; al-

though conditions in tubes 43 feet long, 4¾-inch I.D. are difficult to judge.

The unit went back on stream and operated 35 days, when it became necessary to shut it down because a small hole had developed in a furnace tube. The tube, located near the coil outlet of the radiant section of the fired crude heater, was removed and sectioned to determine the extent of the corrosion. It was thin near the middle, with wall thickness gradually increasing toward each end. The hole had resulted from severe localized corrosion inside the tube at the point of contact with the middle hanger, and the tube was generally thinner on the bottom (fire side) throughout most of its length. Four other tubes in the same vicinity were too thin for further service. Because the earlier analysis of deposits from the flash section of the atmospheric tower had indicated that sulfide corrosion was taking place, 7 percent Cr-0.5 percent Mo alloy tubes were installed as replacements because their resistance to such type of attack is well known.

The still was returned to service; but it came down again 37 days later with holes in two tubes adjacent to the tubes previously replaced. The holes in these tubes were also located at points of contact with hangers. On this shutdown, the Penetron, which was not available at the time of the first emergency shutdown, was used to check all radiant tubes in the atmospheric heater. Thirty-nine tubes were condemned due to thinness on the fire side, due allowance being made for the localized corrosion near hangers. Seventeen were replaced with 7 percent Cr-0.5 percent Mo alloy (all of the alloy tubes available at the time), and the balance replaced with carbon steel.

The tubes of the vacuum heater were also inspected, using the Penetron, but no eccentric corrosion was found in the carbon steel tubes of the radiant section of that heater; this, in spite of the fact that oil temperatures and sulfur content of the charge to that heater were higher than those of the charge to the atmospheric heater.

On the subsequent regular turnaround, which occurred in July, 1949, the following repairs were made. The flash section of the atmospheric tower was strip lined with stainless steel, Type 410. The three top overhead condenser shells were replaced and the admiralty metal tube bundles for these condensers were renewed due to the corrosion of the carbon steel baffles. The new tube bundles were made up using admiralty tubes and brass baffles. It was also necessary to replace 11 additional carbon steel tubes in the atmospheric heater. All other equipment was found to be in good condition.

The Corrosion of Furnace Tubes

A careful study of this tube corrosion revealed a number of important facts and emphasized certain fundamental factors which had accelerating influences.

A sectional view of the first radiant tube which failed in the atmospheric heater is shown in Figure 2. The rapid thinning near the point of contact with the hanger can readily be seen. This accelerated at-

LOCATION OF HANGER

Figure 2—Sectional view of tube 95.
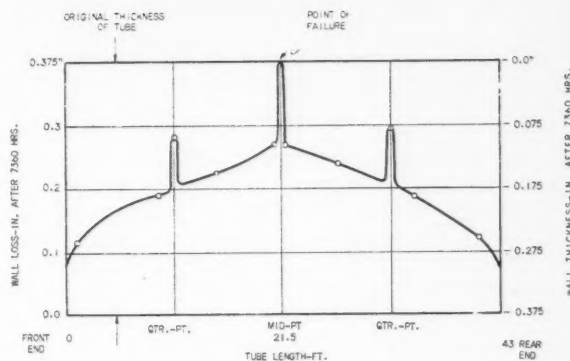
Figure 3—Corrosion of tube No. 95—fire side.

tack appeared to be due to the fact that the hangers, which were curved to fit or cradle the tubes, acted as fins resulting in high input of heat at those points. Then, in turn, the higher local oil film temperatures resulted in increased chemical reactions between the sulfides in the crude and the iron of the tubes. Accelerated attack on the fire side of radiant tubes has been experienced on other units also, but to a lesser degree, and then only after years of service. Mr. L. R. Gray noted that this type of corrosion was experienced at Shell's Wood River Refinery when processing "sour" West Texas crude.[7]

In attempting to understand this eccentric corrosion in furnace tubes, it should be noted that an analysis of "Temperature Distribution in Tubes of Refinery Pipe Stills," by Mr. J. W. Bonner, disclosed that considerable differences may exist between the tube wall temperature on the fire side of a still tube compared to those on the opposite or shielded side.[8] Under certain conditions, his analysis disclosed differences as great as 170° F between the average tube wall temperature on the fire side and that on the opposite side. The same difference in temperature was found to exist between the tube (fire side) and oil mass temperature. Therefore, it is postulated that the *oil film* temperatures on the hot side of tubes must be much higher than *average* oil temperatures, and that it is the *film* temperatures which actually govern the cor-
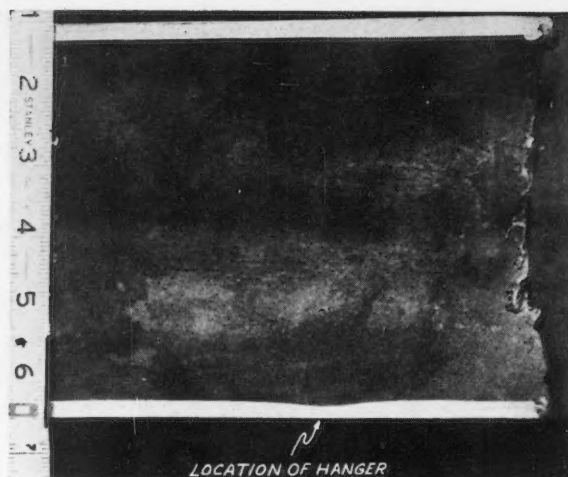
Figure 4—Sectional view of tube 84.

Figure 5—Comparison of corrosion rates for carbon steel furnace tubes in crude distillation units. I—In Ordovicion crude service. II—In high sulfur crude service. III—Reported case for topped high sulfur crude.

rosion rates. No case has come to the attention of the writer which has provided better proof of this theory than the experience with the furnace tubes under discussion.

This marked influence of temperature upon the corrosion rate for carbon steel tubes is also demonstrated by a study of that rate in various parts of the same tube, where we know that the temperature of the oil mass did not vary appreciably. Measurements of wall thickness along the wall on the fire side of Tube No. 95, from end to end, are given in Table III; and the plotting for these rates is shown in Figure 3. The rapid increase in corrosion rate is apparent as the distance from the relatively cool header box increases and extends toward the middle of the firebox, where higher heat transfer rates may be expected. The extreme peaks at each hanger are clearly indicated, demonstrating forcefully the response of the corrosion rate to localized temperature increases. The tube hangers have been observed to glow cherry red, corresponding to temperatures around 1450° F at their lower edges, and darken rapidly toward points of contact with the tubes, indicating a high rate of heat input at such points.

Several tubes were sectioned and showed a corrosion pattern similar to that found in Tube No. 95, but the severity of the corrosion decreased materially on those tubes located nearer the side walls of the furnace. For example, Tube No. 84, pictured in

Figure 4, showed less corrosion on the fire side and at the point of contact with the hanger than did Tube No. 95. The wall thickness of Tube No. 84 at point of contact with the middle hanger was 0.170-inch.

Possibly, temperatures of the oil film should be considered more often when discussing corrosion rates at various temperatures in processes. This consideration appears impractical for most purposes, yet it is of more than academic interest when comparing corrosion rates for tubes in furnaces of different design, as will be discussed later.

Comparison of Corrosion Rates

The marked effect of temperature on the corrosion of carbon steel furnace tubes by "Ordovician" crude is again graphically portrayed in Figure 5, as Case I. The "peak" corrosion rates of tubes in this new unit are compared to those reported for furnace tubes used in processing sour crudes. The oil temperatures used are temperatures of the oil mass as recorded by conventional pyrometers, although some interpolation was necessary in arriving at certain of these temperatures. Corrosion rates are expressed as wall loss in inches per 1000 hours. "Peak" corrosion rates for the tubes in this unit are based on wall losses on the fire side of the tubes away from the hangers, rather than the corrosion at points of contact with hangers; as such rates were considered to be more comparable to the other "peak" corrosion rates shown in Cases II and III. The effect of temperature on corrosion of carbon steel furnace tubes in a distillation unit running West Texas crude with a sulfur content of 1.5 percent is presented as Case II. Case III shows the same effect when processing "topped" sour crude, 1.5 percent sulfur.[9] The corrosion rate for the furnace tubes in the new unit processing low sulfur crude is higher than that for the tubes used in processing "topped" sour crude, but somewhat lower than that for tubes used in raw sour crude service. Neither of the crudes involved in Cases II or III had been desalted.

Corrosive Agents and Rate Factors

With corrosion of this magnitude involved in the processing of this low sulfur crude, the question

TABLE III
Wall Thicknesses and Losses On Tube No. 95*
(After 7360 Hours in Service)

CALIBRATION POINT	WALL SIDE	FIRE SIDE	
	Thickness (Inches)	Thickness (Inches)	Loss (Inches)
3 Feet from Front Wall	....	.285	.090
8 Feet from Front Wall	.315	.186	.189
15 Feet from Front Wall	.286	.143	.232
MIDDLE (4 inches from Hanger)	.232	.115	.260
15 Feet from Rear Wall	.280	.140	.235
8 Feet from Rear Wall	.310	.180	.195
3 Feet from Rear Wall	....	.280	.095
AT FRONT HANGER	....	.105	.270
AT MIDDLE HANGER	.230	.000 (Hole)	.375
AT REAR HANGER	....	.095	.280

* Original wall thickness of tube: .375 inch.

Figure 6—Peak corrosion rates at 550 degrees F. Carbon steel furnace tubes.

arises whether or not all possible corrosive agents in the crude have been considered. The principal elements in crudes which have been known to contribute to accelerated corrosion at high temperatures have been sulfur or sulfur compounds and organic acids such as the naphthenic acids in certain crudes. Also, the possibility of acid salts and free hydrochloric acid entering into a corrosion cycle in the presence of sulfides has been suggested as an accelerating influence in high temperature corrosion by one writer.[10] However, the chloride content of the crude charge was very low after desalting, 2.5 lb. NaCl equivalent per 1000 barrels. Acidic constituents were practically nil; neutralization numbers for lube distillates were 0.02 to 0.03. Furthermore, as previously noted, the scale deposits which were analyzed consisted principally of iron sulfide. Consequently, this leaves sulfur compounds as the most important corrosive agents.

Apparently, appreciable quantities of the sulfur compounds in the crude were of the type which decompose or become very active at temperatures near 550° F and above. Furthermore, even at such low concentrations as 0.20 percent, over 13,000 lb. of sulfur per day passed through the crude heater furnace tubes when the still was charging 24,000 bbl. per day. Thus, if all of the sulfur had been reactive and had contacted the metal, this would have been sufficient to completely corrode all of the original radiant tubes in 5 days. Assuming something more plausible, if one-fourth of the sulfur had been reactive at the temperatures encountered, and only one-tenth of that had come in contact with the steel tubes, then all of the iron in these tubes would have been completely consumed within 120 days. Actually, the unit operated 306 days before the first small hole appeared in one furnace tube.

The most significant rate factor in this corrosion case is temperature. Differences in tube wall temperatures within the same tube have demonstrated their effect upon the corrosion rate. Turbulence is considered to be a minor factor, because the tube ends and carbon steel headers showed little corrosion in spite of relatively high velocities near the coil outlet, where partial vaporization took place. A few headers near the coil outlet showed corrosion-erosion grooves over a small area which resulted in only 0.05-inch loss after 14,304 hours of service.

The fact that the charge to this unit was a clean desalted crude resulted in clean tube surfaces which the corrosive elements could contact. That such a clean condition is a factor in corrosion is often overlooked. Marked increases in the corrosion rate of carbon steel furnace tubes have been experienced on other crude units, due to the elimination of deposits in the tubes following the installation of desalting equipment.

Comparison of Old and New Units

Prior to the construction of the new unit, the "Ordovician" crude was processed in an older atmospheric-vacuum distillation unit without corrosion difficulties.

The charge rate to the older unit was 17,500 barrels of "Ordovician" crude per stream day compared to 24,000 barrels for the new unit. Pressures in various parts of the systems were very nearly the same. The crude was desalted in the same type electrical desalting equipment as that used on the new unit, and the salt content of the crude, before and after desalting, was approximately the same as previously reported. Sulfur content averaged 0.18 percent of the crude during the period when it was charged to the older unit, and the quantity and distribution of the sulfur in the products were very close to those shown in Table I under "Ordovician" crude.

The condensing systems for the atmospheric tower overhead vapors were quite different on the two units. The vapors from the atmospheric tower on the older unit were condensed in cast iron pipe coils submerged in an open water box. Because cast iron pipe is quite resistant to the corrosion in such service, there was no indication of the corrosion which might be expected in the tubular condensers on the new unit.

Comparable operating data for the crude heaters of the two units are shown in Table IV. The most significant difference in operation is the higher temperature of the oil from the crude heater on the new unit, 605° F; compared to 553° F on the old unit. At first glance, it would appear that the higher corrosion rates for the furnace tubes on the new unit might thus be explained. That conclusion is partly true when discussing corrosion rates in the roof radiant tubes but does not explain the short life of the carbon steel tubes in the new unit where oil temperatures were 550° F. Figure 6 shows the "peak" corrosion rates for both units where oil temperatures were the

TABLE IV.
Comparison of Data, Crude Heaters On Old and New Units

CRUDE HEATERS:	Old Unit	New Unit
Crude Charge: Bbls./Day	17,520	24,430
Oil Temperatures: °F.		
To Heater	227	345
To Radiant Section	460	477
From Radiant Section	553	605
Rise in Radiant Section	90	128
Radiant Section:		
Surface Area of Tubes: Sq. Ft.	3,636	4,378
Heat Absorption in Oil: B.t.u./Bbl.	38,500	47,600
Heat Absorption in Oil: B.t.u./Sq. Ft./Hr.	7,730	11,050
Inlet Velocity*: Ft./Sec.	5.47	6.44
Outlet Velocity*: Ft./Sec.	5.47	3.22
Mass Velocity in Outlet Tubes:		
Lbs./Hr./Sq. Ft. of Cross Section	992,500	586,000

* Oil volume as liquid @ 60° F.

same. The corrosion rate for tubes on the new unit was four times that for tubes on the old unit at oil mass temperature of 550° F, so there must be factors other than oil mass temperature which account for this difference.

The arrangements of the tubes in the radiant sections of the crude heaters for the new and old units are shown in Figures 7 and 8, respectively. The tubes of the radiant section on the new unit which carried the oil in each pass at temperatures approximating 550° F were located along the side walls a few feet away from the flames of 20 burners. The tubes which carried the hottest oil at 605° F near coil outlets were in the roof, arranged in a single row, two tubes in parallel for each pass.

In the older unit, the top row of roof tubes, which were somewhat shielded from maximum radiant heat by the lower row, carried the oil at 550° F. Flow was through each tube singly in each pass. There were four fan-mix type burners located in the front wall, and tubes in the immediate vicinity of these burners carried oil at oil mass temperatures below 375° F, which is considerably below temperatures where sulfide corrosion becomes serious.

Both units were gas fired and firebox temperatures ran close to 1400° F at the bridge walls.

Referring again to operating data in Table IV, differences between the oil velocities in the two units were not significant. The velocities given in this table are calculated oil velocities based upon the volume of the oil at 60° F. The actual combined oil and vapor velocities at tube outlet temperatures were much greater than those shown in the table, due to temperature considerations and to a certain amount of vaporization of the oil.

The average heat transfer rate for radiant tubes in the new unit was 11,050 Btu./Sq. Ft./Hr., compared to 7730 for the old. Again, basic concepts of heat transfer indicate that oil film temperatures were appreciably higher in the radiant section tubes of the new unit, and the higher oil film temperatures must have caused the higher corrosion rates in the furnace tubes of the new unit. Certainly, the accelerated attack on the tubes at the points of contact with tube hangers in the new furnace clearly demonstrated the effect which high local heat input had upon the corrosion rate.

Thus, it may be concluded that basic differences in furnace design influenced the corrosion rate of carbon steel heater tubes through differences in tube and oil film temperatures.

This experience should cause one to wonder about the dependability of corrosion rates which previously have been reported in the literature without knowing more details about the design of the equipment involved. Corrosion experiences in the older fired heaters employing certain heat transfer rates should not be used in estimating the corrosion which might be expected in more modern units where higher heat transfer rates are used. It is not suggested that designs be changed, since the newer units are more efficient. The remedy lies in the use of more intermediate alloy tubes in new distillation equipment. This is especially true where certain low sulfur crudes
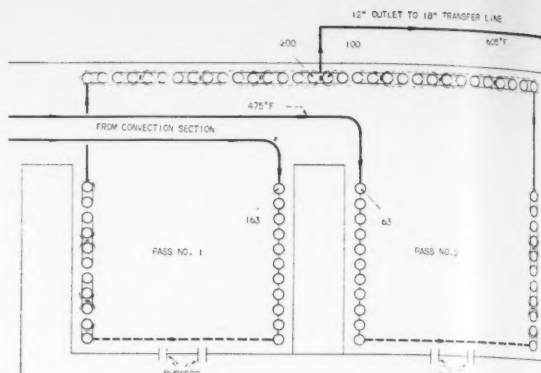
Figure 7—Radiant section, fired heater for atmospheric tower feed. Tubes are 5½-inch O.D. by 4¾-inch I.D. by 43 feet long.
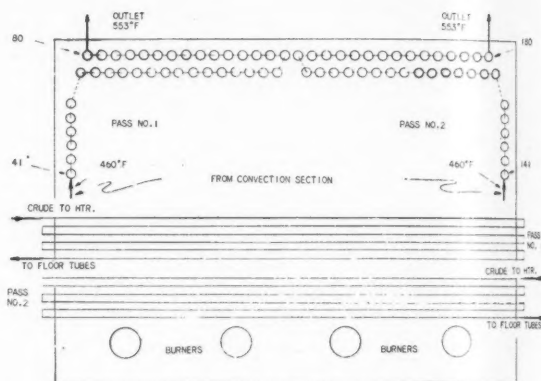
Figure 8—Radiant section, fired heater for atmospheric tower feed, old unit. Tubes are 5-inch O.D. by 4⅜-inch I.D. by 30 feet 7 inches long.

which evolve appreciable hydrogen sulfide during distillation will be the charge; where fired crude heater outlet temperatures exceed 550° F; and where oil film temperatures may be high as a result of high heat transfer rates.

Results of Recent Inspection

An inspection of the new unit in January, 1950, disclosed that ammonia had not entirely eliminated the corrosion of the atmospheric tower overhead condensers, but had reduced it to a satisfactory degree. The condensing process steam is sufficient to dissolve any ammonium chloride which may be formed. Although a small quantity of iron sulfide precipitate causes some fouling of the condensers, runs of about six months are scheduled for this unit.

The 12 percent chromium steel strip lining which had been installed in the flash section of the atmospheric tower in July, 1949, was in excellent condition; but the lining may have to be extended up another 8 to 10 feet in the tower in the near future. The carbon steel shell of the tower in the middle and upper portions was not attacked to any measurable degree, and the Meehanite trays in the tower were holding up well.

Although no corrosion of the alloy lining on the vacuum tower had been noted previously, the recent

inspection disclosed several small isolated pits in the lining of the flash zone. Further investigation of this attack will be necessary, and minor repairs by welding may be required from time to time. The fabricated alloy trays and caps in the vacuum tower were in excellent condition.

The atmospheric tower side stream strippers were unattacked and the strippers for the vacuum tower side streams were in good shape with one exception. The stripper for the lower vacuum tower side stream had lost 0.03-inch in wall thickness.

The 7 percent Cr-0.5 percent Mo alloy tubes which replaced the carbon steel tubes in the radiant section of the atmospheric heater showed only minor wall losses, 0.01 to 0.02-inch in 6048 hours of service. That was the equivalent of 8 percent of the corrosion rate for the original carbon steel tubes. The carbon steel tubes located along the side walls of the fired heater for the vacuum section had lost very little metal, 0.02-inch in 14,304 hours of service.

It should be worthy of note that, in spite of the corrosion difficulties experienced on the new unit, the on-stream time for the year 1949 was 93.9 percent. Part of this accomplishment was attributable to the fact that some alloy tubes were available from the spare stock of two other new distillation units which processed sour West Texas crude. Prompt delivery of additional alloy tubes from the steel mills was also a factor in supplying tubes when needed. If spare tubes had not been readily available, lost time on the unit could have resulted in rather serious economic losses.

Summary and Conclusions

The study of the corrosion on this unit has shown that a low sulfur crude may be extremely corrosive to carbon steel furnace tubes of a distillation unit under certain conditions. This fact demonstrates rather forcefully the point that the percentage of sulfur in a crude is not a direct measure of its tendency to corrode. The corrosion rates in the tubes in the crude heater processing "Ordovician" crude proved to be severe above temperatures of 550° F (oil mass temperature) and very sensitive to oil film or tube wall temperatures.

Because heat transfer rates and tube wall temperatures may vary considerably from one design to another, appreciable differences in corrosion rates for furnace tubes may be expected with a given crude

if processed on units of different design. Corrosion engineers and designers should consider the advisability of specifying more alloy furnace tubes for oil temperatures above 550° F on crude units designed to process low sulfur crudes which evolve appreciable quantities of hydrogen sulfide during distillation.

The problem has been presented in as much detail as possible to permit correlation with other experiences. The review of past corrosion experiences within a refinery, or those reported in the literature, may be helpful; but such review may be misleading unless all possible factors bearing upon the problem are investigated. As more experiences with modern equipment are revealed, better guides to corrosion control in new units should result.

Cooperation among corrosion engineers, chemists and designers should be helpful in properly anticipating the corrosion which may be expected in any proposed refinery equipment.

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Corrosion in Condensate
And in High Pressure Sweet Oil Wells*

By R. C. BUCHAN

ABOUT THE AUTHOR—R. C. Buchan is in charge of the Chemical Engineering group of The Humble Oil & Refining Company's Production Department. He has been employed in chemical work by Humble since he obtained a B.S. degree in Chemical Engineering from Texas A. & M. in 1930. A substantial part of his time during the last several years has been devoted to corrosion problems. He has written several API papers, including one on corrosion. He is a member of NACE Committee TP-1.

Abstract

The problem of corrosion in condensate and high pressure wells producing sweet oil is discussed. The corrosion problem encountered in condensate wells is rather well known, but it is not generally known that a very similar problem exists in a large number of oil wells. The work that has been done on these two problems is reviewed and current practices are summarized.

The mechanical aspects of equipping and completing wells in which corrosion is a problem are discussed. Leakage through threaded tubing connections is an important subject which needs study in conjunction with corrosion preventive work. Attention is being given to joint designs, thread lubricants, and tubing installation practices. The various ways that wells can be completed in order to permit control of corrosion are discussed.

Detailed discussions are devoted to the various materials that can be used for tubing and for wellhead assemblies in these services. The use and relative value of materials reported on include low carbon steel tubing, 9 percent nickel steel tubing, internally nickel-plated tubing, and plastic-coated steel tubing. A review is presented of the various chemicals that are used as neutralizing agents, emulsifying and/or wetting agents, and other film-forming materials. The relatively new use of sodium silicate is discussed in detail. The procedures followed in the use of chemicals are given.

The methods of determining the corrosive conditions and the efficiency of methods used to prevent corrosion are summarized.

SINCE THE CORROSION problem in condensate wells was recognized in 1943, a great deal of work has been done toward finding economic solutions. In 1945, it was found that a similar problem existed in deep high pressure oil wells in Louisiana. The mechanical phases of these two problems are at least as important as the chemical phases.

Shortly after corrosion of wellhead assemblies and flow lines on condensate wells was found, it was established that corrosion of tubing in condensate wells was a widespread and serious problem. Work was started in committees of the Natural Gasoline Association of America (NGAA), the American Petroleum Institute (API) and the National Association of Corrosion Engineers (NACE). The U. S. Bureau of Mines undertook work on the problem as well, as did the research and operating departments of the producing companies. All these agencies are still doing work on the problem. A number of manufacturers of chemicals and equipment have also worked on the problem and are continuing their efforts. The NGAA's earlier efforts were directed principally toward sponsoring research work to establish the causes and find possible preventive measures. The API has studied the problem from an over-all standpoint and has devoted its principal efforts to accumulating factual data and evaluating preventive measures. The NACE's principal endeavor has been in the study of alloys, but all aspects of the problem have been given individual and cooperative attention.

The present status of the whole problem as pertains to condensate wells can be briefly summarized as follows. There are about 1000 condensate wells in which corrosion is of economic importance. Suitable alloys have been found for use in wellhead assemblies and for special tools installed in tubing strings.

Several chemical means have proved to be satisfactory for use either as neutralizing agents or as inhibitors. Other chemical means are being tested and are under observation. Various materials are in service in tubing, but none has as yet been definitely established as an economic solution to the tubing problem in general. Considerable work remains to be done on the problem of equipping wells so as to cope with both the corrosion problem and the pressures encountered. This last includes such problems as threaded joint design and thread dopes.

The corrosion of tubing in flowing oil wells of 8000 feet or more in a number of Louisiana and Mississippi fields is similar to that in condensate wells. It is estimated that about 300 wells are affected. The problem differs from the condensate problem in that the wellhead and top 1000 to 2000 feet of the tubing are protected by paraffin deposits until the well produces a high percentage of salt water. Because of the paraffin and emulsion treating problems and because tubing is set on a packer, the apparent solution is to find a suitable tubing material. As is discussed later, plastic-coated tubing appears to be a suitable material.

Condensate and oil wells are completed by either suspending the tubing from the wellhead assembly

or by setting the tubing on a packer near the bottom of the well. In the first-named type of completion, the full well pressure is imposed on the casing. In the second type of completion, the annular space between the tubing and the casing is filled with drilling fluid or with water, thereby confining the well pressure to the inside of the tubing. In the absence of corrosion, the materials selected for casing and tubing in such wells depend on their physical characteristics, taking into account the changes that occur during the life of the wells. Low-carbon steel tubular goods meet the physical requirements. The API specifications for tubular goods do not take corrosion into consideration. Experience has shown that, where conditions are such that wells can be completed and operated with pressure on the casing, the use of chemicals to control corrosion of these mild steels is a feasible and economical solution to the corrosion problem. Where a corrosive condition exists and where pressures or other conditions dictate that the tubing be set on a packer, experience to date is such that no generally acceptable method has been found to control corrosion of the inside of the tubing.

Leakage of threaded connections in the tubing string when set on packers is a common problem in all types of oil and gas wells. Where the produced fluids are not corrosive, small leakage is ordinarily considered of minor importance because the rate of leakage seldom increases rapidly. Where the produced fluids are corrosive, leakage, once started, increases rapidly due to the fact that the threads begin to corrode, which in turn permits movement of more fluid which accelerates the rate. Surveys made by committees of the API indicated the need for considerable work, and the API has started research work on suitable thread lubricants and is reviewing joint designs.

Several of the producing companies have made independent studies of thread leakage and are improving their field practices in regard to installing tubing strings. The most significant recent changes which are being adopted include the use of higher and more uniformly applied torque when making-up joints, the selection and use of thread dopes that have been bench-tested and have shown the ability to act as a sealing material in addition to serving as a lubricant and as an antigalling material. The mke-up torque commonly used on nominl 2-inch upset tubing is 1500 to 2000 foot-pounds and 2000 to 2500 foot-pounds on nominal 2½-inch tubing. Several operators have begun the practice of removing couplings from API pipe, thoroughly cleaning all threads, applying a suitable dope, and making-up the joint with the coupling "floating," i.e., both pair of threads are made-up at the same time. Considerable study has gone into the design of possible threaded connections so as to improve leakage resistance. The real importance of obtaining leakage resistance in fields in which corrosive conditions exist lies in the fact that, if leakage permits corrosion of the threads with subsequent aggravated leakage, a workover job must be performed to correct the condition. Additional money invested in corrosion resistant tubing materials cannot be justified easily unless all

workover jobs are eliminated because usually only about 20 to 25 percent of the cost of the workover is for material that has to be replaced.

One method of controlling corrosion in gas wells while still controlling well pressures involves the careful design of casing programs or the installation of a full length liner to permit holding well pressure in the casing or inside of the liner. With this arrangement, chemical control of the corrosion is both possible and economically feasible. It is probable that more wells will be equipped in such a manner, and if so, ordinary steel tubular goods should suffice.

Tubing Materials

Steel tubing is not an uniform material from a corrosion standpoint. Figure 1 shows a caliper survey of a well in which corrosion has advanced to a serious condition, and it is interesting to see that a number of joints located at random in the string appear to have not been affected by corrosion. This condition has been found in quite a few wells, and it clearly shows the lack of uniformity in the corrosion of individual lengths of tubing exposed to the same environment. If it were a uniform material and if corrosion could be distributed throughout the tubing string, corrosion would not be of economic importance. Failures, as is well known, are due to pitting, and there are numerous factors which cause this to be so. Some of the factors are the conditions of mill scale when the pipe is installed, the lack of uniformity of grain structure, the presence of various types of mill defects which are of little or no importance from a physical standpoint, stresses present, and stresses imposed on the string by installation and use. Companies that have been coating pipe with baked-on resinous coatings have found it necessary to inspect all pipe after it has been prepared for coating so as to cull an average of 2 to 3 percent which contains defects of a nature unsuitable for coating. In some batches of tubular goods, it has been necessary to cull as high as 30 percent. If a user were to carefully inspect and cull black pipe that is to go into condensate service, it is possible that some early failures could be avoided and the service life of the string might be increased, but this by itself would not affect the general picture much. Some improvement in the culling practices of black pipe at the mills is indicated from a corrosion standpoint. Figure 2 shows an unusual mill defect, but it should be remembered that it takes only one serious mill defect and localized corrosion to cause a work-over job.

Two strings of galvanized tubing have been used in oil wells in the Bayou Sale Field in Louisiana. The life of one was no better than the black tubing it replaced. The other was replaced before it actually failed. This is as would be expected and substantiates the NACE's spool tests.

One of the principal objectives of making the NACE spool tests was to indicate suitable materials for condensate well tubing. The tests showed that 9 percent nickel steel appeared feasible, and it has been installed in about 50 wells operated by about 10 different companies. None of it has been in service long enough to permit good evaluation in compari-

0-1650'
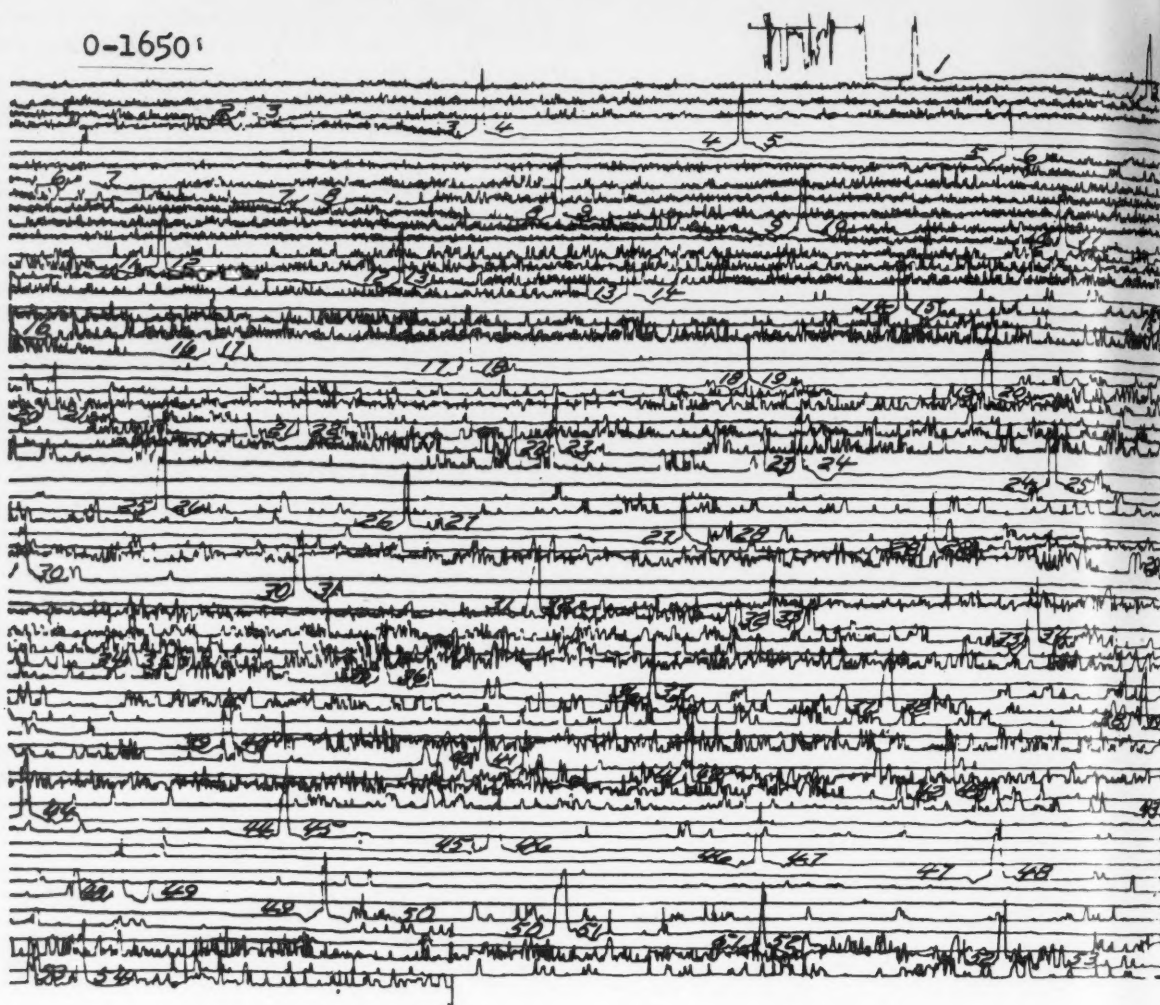
Figure 1—Caliper survey in condensate well tubing. Note unaffected tubing lengths.

son with black pipe. It costs about $2.00 to $2.40 per foot complete and ready for installation and varies in price depending upon size and type of joints used. In the most extremely corrosive wells or in isolated cases, such as in marsh or water locations where workover costs are excessively high, such expensive alloys appear justified. However, it is doubtful whether such a material will ever be widely used unless a lower price is possible to the gas producer. Producers operating a relatively large number of corrosive condensate wells find that the average well is such that corrosion losses, when using black pipe and replacing it as it becomes necessary, amount to the equivalent of about $1.50 per foot for a material which will give 8 to 10 years of trouble-free service. In other words, if an operator has to replace black tubing every 3 to 4 years, the cost of the program over a period of 8 or 10 years does not justify paying more than about $1.50 per foot for tubing. Alloy tubing is, of course, in competition with other methods of controlling corrosion such as the use of inhibitors and other types of tubing materials. Elec-

trolytic action between the outside of the tubing and the inside of the casing is potentially serious; if the two are dissimilar metals, this raises a question which still needs to be answered. The reported failures of such alloys by embrittlement in hydrogen sulfide service requires careful observation in condensate service because cases of embrittlement of bull plugs and other low carbon steel equipment have been reported. It is possible that embrittlement can occur, and probably the only way that this can be properly evaluated is by actual service.

Five percent nickel steel and other low alloy steels may find some economic use; however, the NACE tests in combination with the work done by the Bureau of Mines would indicate that 9 percent nickel is to be preferred, particularly in view of the small price difference.

The only other material tested in the NACE spool tests that appears feasible for tubing is nickel-plated steel. Two strings of such tubing have been in service for about 4 to 6 months which is too short a time to evaluate the material. Water samples taken from
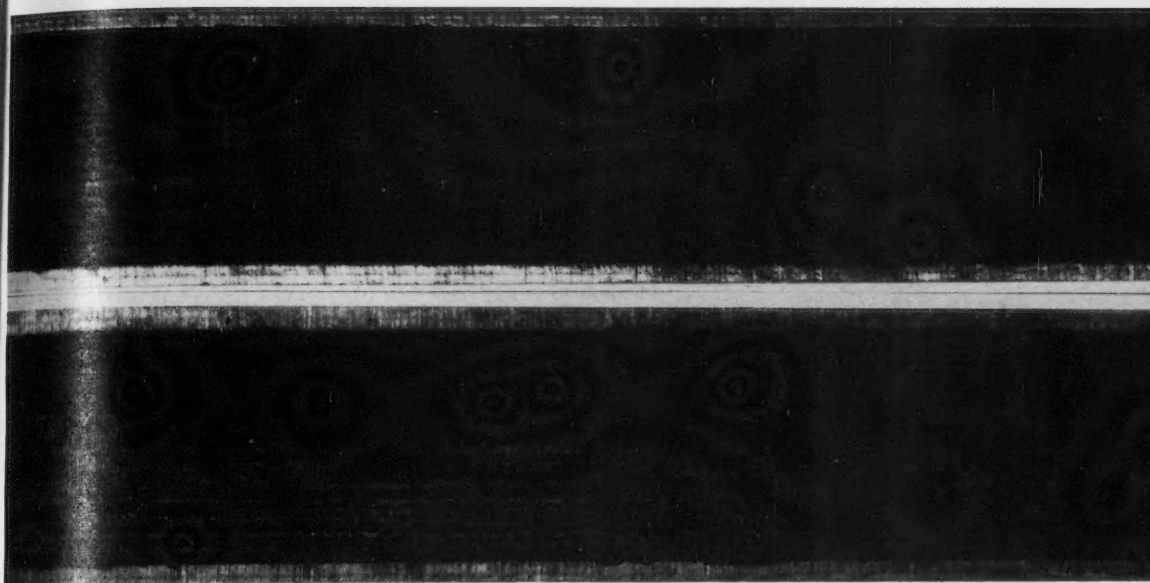
Figure 2—Internal corrosion of oil well tubing aggravated by unusual mill defects.

wells equipped with nickel-plated tubing indicate that the iron contents are in the range from 30 to 90 parts per million as compared with 200 to 250 parts per million when black tubing was used. Caliper surveys have not as yet meen made. The tubing in service has been plated by one manufacturer, and a second manufacturer has developed procedures to the point where the material may be more readily available. Currently, the cost of nickel-plated tubing is about $1.50 a foot, and if continued improvement is made in procedures and if suitable volumes are used, this price can probably be reduced to $1.25 a foot or less. Nickel-plated tubing at present is still in the experimental stage, but its wider trial appears to be justified.

Plastic-Coated Tubing

Tubing coated internally with baked-on phenolic resins was tried in 10,000-foot corrosive oil wells before trying it in condensate wells. Figure 3 indicates the differences in service life obtained from coated and uncoated pipe in oil wells in the Bayou Carlin Field in Louisiana. The coated string was installed in August 1945, and the uncoated strings were installed in January and March of 1946. The caliper surveys used in Figure 3 were made in July 1949. These are the only wells in this field and their production histories are similar. Pipe line oil was produced for 6 to 12 months after completion, and the salt water production increased gradually to above 75 percent. Earlier caliper surveys in uncoated pipe and visual inspections revealed that the condensate type of corrosion occurred before salt water production started. Electrolytic corrosion due to carbon dioxide in the salt water appears to be as bad and possibly worse than that due to acidic fresh water. The picture is generally the same in the Bayou Sale Field which has about 80 producing wells. A difference exists in the carbon dioxide content of the gas from the several reservoirs at Bayou Sale in that it varies

from 0.75 to 1.2 percent. The approximate life of black tubing is 3 to 8 years and is shortest where the carbon dioxide content of the gas is highest.

Tubing properly coated with baked-on phenolic type plastic coatings has proved to be economically feasible as a corrosion preventive measure in deep oil wells similar to those discussed. It costs about $1.00 per foot or about twice the cost of uncoated tubing. Plastic coatings have not as yet been used in many gas-lift wells where they may fail from localized erosion, but in such wells, corrosion can be controlled with chemicals at about an equal or possibly lower ultimate expense.

The experience with plastic-coated tubing in condensate wells has not been as good as in oil wells, but the picture is distorted because of the thread leakage problem. There have been about 120 strings installed by all companies and about 25 strings have been reset or replaced after an average of about two years of service. About 10 of the strings were pulled because of joint leakage. There are a number of strings that have been in service more than three years, and caliper surveys show that they are in essentially new condition.

Plastic-coated tubing can be used economically as a corrosion preventive measure in a large number of condensate wells. Such a practice has limitations, the principal one of which is the care necessary in preparing and coating pipe. Other limitations are that it is possible to damage coatings with tools and wire lines run inside of tubing, and it appears that in wells that produce at very high rates, erosion may be a factor leading toward early failure. In fields in which regulators or chokes are set in the tubing string, it is believed to be good practice to use one or two joints of 9 percent nickel steel or nickel-plated steel above the tool to obtain protection against erosion and corrosion at this critical point.

It has been found that, in order to obtain a good
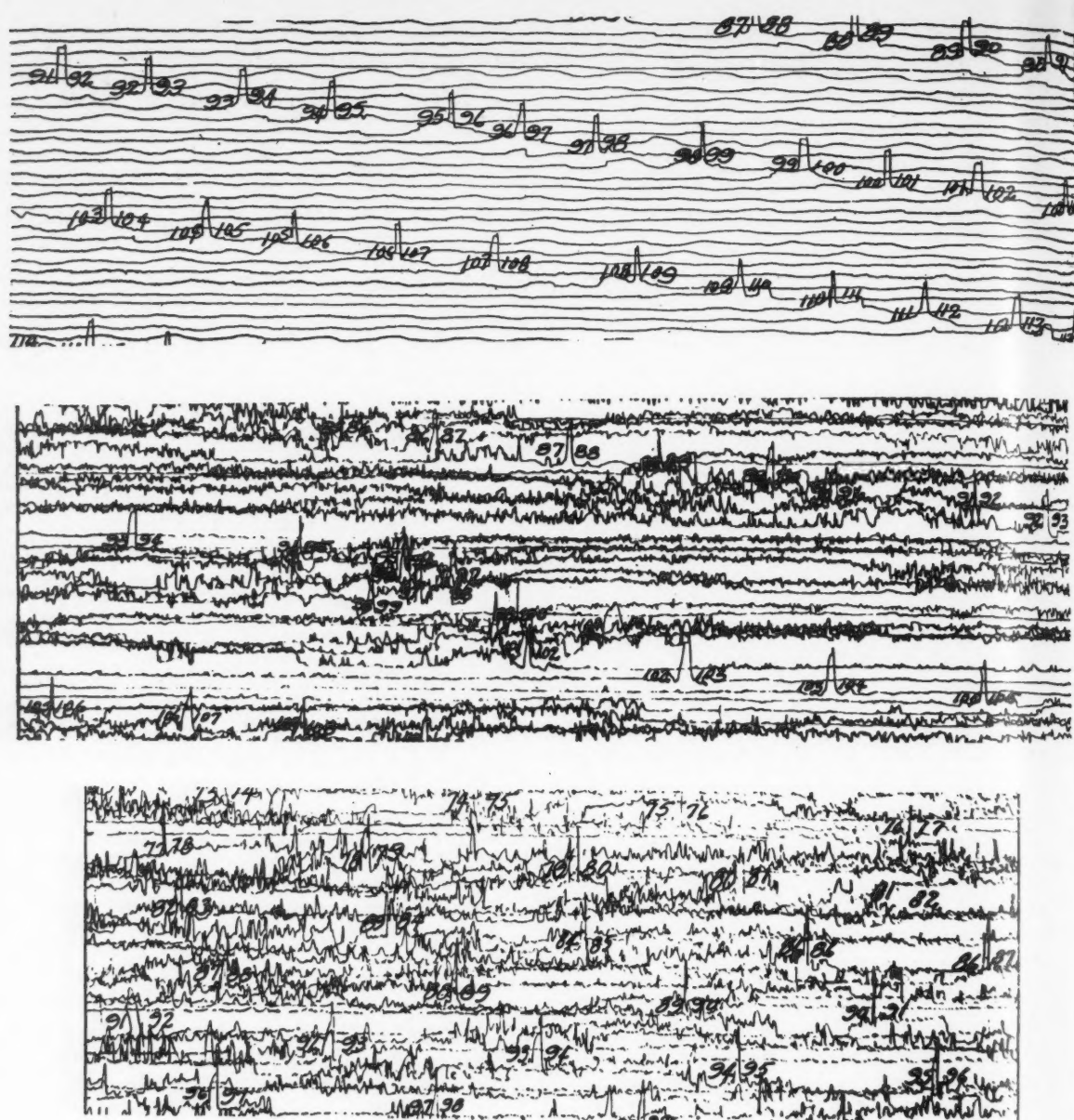
Figure 3—Comparison of coated and uncoated tubing in Bayou Carlin oil well service. Tops survey is in coated pipe after 3.9 years' service. Other two surveys are in uncoated pipe after 3.4 and 3.5 years' service.

plastic coating, tubular goods have to be thoroughly cleaned to the bare metal and have to be inspected by boroscope methods so as to cull mill defects in the pipe which cannot be satisfactorily coated. Such defects include overlaps, inclusions that cause cracks in the surface of the material, and pits having sharp edges. Some of the failure of coated pipe can be attributed to poor and not very thorough culling of pipe before it was realized that these extra precautions were necessary. Some of the failures have been due to having the coating too thick in spots as a result of "runs" of the plastic material before baking. Advances have been made in the techniques of preparing and coating pipe so that the present product

is an improvement over that obtainable three or four years ago.

One question frequently asked with reference to plastic coating tubing pertains to whether coating should be applied to threads. Obviously, if care isn't taken when coating threads, the coating could interfere seriously with make-up which also may affect leakage. Included in a series of tests studying leakage of the API threaded connections were tests in which the thread elements were coated in various ways. These tests reveal that a coating having a thickness of 0.003 to 0.004 inch, although it affects thread standoff, does not affect the leakage resistance of the joint when compared with uncoated threads.

In other words, coated threads are similar to uncoated threads, but from a corrosion viewpoint, it is desirable that the thread elements be coated so that a continuous film of plastic is obtained in a tubing string.

Neutralizing and Inhibiting Chemicals

Data recently accumulated by the NGAA Subcommittee on the Use of Inhibitors indicate that the use of chemicals to raise the pH of the produced water and the use of chemicals that act as inhibitors probably give the operator the most economical methods of controlling corrosion in condensate service. This is true, particularly in larger fields, provided that the wells can be equipped so that injection of the chemical is possible in the lower part of the tubing string. Chemicals injected in such a manner protect the tubing, the flow lines, and any other surface equipment.

Soda ash solutions have been used to advantage in the Katy Field for about four years resulting in a minimum cost for corrosion prevention. The total cost of this operation is about $50,000 a year, or about $0.28 per million cubic feet of gas produced. Tubing caliper surveys and water analyses show that corrosion in the Katy Field is almost completely controlled. Other neutralizing agents in use in the industry include ammonia, sodium bicarbonate, and sodium hydroxide. These inorganic materials have a disadvantage, i.e., continuous injection is necessary because there is little "lasting" effect. Another objection is that freezing of the water solutions and the formation of hydrates in the gas equalizer lines occur in cold weather. It is possible to form scale adjacent to the point of chemical injection, but such scales can be removed by discontinuing injection for a few days or by using wire line tools such as paraffin removing bits and scrapers. The addition of chromates to the alkaline solutions improves the "lasting" effect, but in view of the increased scaling tendencies, more careful attention has to be given to the methods used in feeding such soltuions.

Chromates are usable to inhibit against condensate corrosion, but they are not as easy to apply as are neutralizing agents or organic chemicals. More care is ordinarily necessary when using chromates to obtain protection throughout the system and to avoid bulky scale deposits.

Organic compounds which cause steel to be preferentially oil wetted or which act as emulsifying agents to keep water from coming in contact with the steel are easier to use than water solutions and appear to be as effective at about the same cost as neutralizing agents. There is one compound in rather wide use at present and several others that are less widely used. It is likely that additional suitable compounds will be developed. These materials have the advantage of having a better "lasting" effect than neutralizing agents. It has been found that, after a well has been treated for a few months and satisfactory protection has been obtained, less chemical or less frequent batch treatments suffice to continue the protection. Some operators use a truck equipped to pump an amount of chemical into each well, while others use pumps or batch lubricators at each well. It usually takes 3 to 6 months after the use of an organic chemical is started to determine the effectiveness as an inhibitor. Apparently, these chemicals tend to remove mill scale and corrosion products because the iron content of the produced water decreases slowly. Frequently, after three months of use, the iron content of the produced water is still about 50 parts per million although it is still decreasing. Coupon tests usually reflect the reduced corrosion rates in 1 to 2 months after treatment is started. There have been relatively few comparative caliper surveys made in wells treated for periods of a year or more with organic chemicals. The few "before and after" one-year-of-treatment surveys that the writer has studied indicate corrosion has been stopped even though the iron content of the produced water has not been reduced to below about 40 parts per million.

In view of the fact that a large number of condensate wells are completed with tubing set on packers, a variety of chemicals in liquid, granular, and stick form have been tried by dumping or pumping them into the tubing string daily or less frequently. No entirely satisfactory chemical has yet been worked out because of the frequency of having to shut-in wells while chemical is injected and the difficulty of feeding a satisfactory quantity. Organic chemicals, if made up in stick form, may ultimately be an answer, provided that the amount of chemical necessary per injection can be reduced or that the frequency of injection can be reduced to about once a week.

Sodium Silicate as a Film Former

The properties of sodium silicate lend themselves to injection into tubing so as to act as a neutralizing agent and as a scale forming material. This was first tried in 1947 by injecting 10-gallon batches of undiluted commercial sodium silicate into several wells. After three weekly injections, they were discontinued because it was found that the scale-like deposits which formed in the wellhead assembly and in the top part of the tubing was rather thick. It was obviout that frequent injections of small amounts of sodium silicate would be objectionable because of the excessive scale formed. About six months later, an internal inspection of the wellheads showed the deposits had not been removed by the fluids being produced. The next attempts using this treatment consisted of pumping 50 or 60 gallons of concentrated sodium silicate solution into each of six wells. After the wells had been shut-in for about four hours, they were returned to production and in two wells bridges were found in the tubing and small plugs were formed in tees in two flow lines. The bridges and plugs were removed rather easily by mechanical methods. An accumulation of solid material was found in several gas-oil separators, and it was removed by washing with water.

Since these early tests, various combinations of quantities and concentrations of sodium silicate solutions and various shut-in times have been used. No exact procedure can as yet be recommended, but it is believed that the following procedure is suitable in most cases. With the well shut-in, 75 to 150 gallons

of a water solution of sodium silicate should be pumped into the tubing as rapidly as possible. The solution should contain 20 to 30 percent sodium silicate or one part of water to 2 or 3 parts of concentrated sodium silicate. The well should remain shut-in for a period of 4 to 12 hours and then be returned to production. The wellhead valves should be thoroughly lubricated before the injection and again a day or two after the injection. The operation of gas-oil separators should be checked for several days after treatments.

The use of sodium silicate to stop leaks in cooling systems is well known. Its use in tubing has stopped leaks in several cases and has reduced leakage in others. It probably has prevented leakage in some cases or can stop very small leaks just started.

Currently, about 200 wells operated by about 20 companies are being treated every 2.5 to 6 months with sodium silicate. It has been found to be rather difficult to evaluate the success of this type of sodium silicate injection as a corrosion preventive measure. Caliper surveys made in 8 or 10 wells in which the treatments have been used for a period of over a year indicate that corrosion has been stopped. Inspection of wellhead assemblies after one or more treatments shows that a scale is deposited which is not easily removed by the well fluids. Careful examination of a string of black tubing removed from a well, because of bad thread leaks, after it had had two silicate treatments, revealed a "paper-thin" film of silicate scale on the surface. This film was not continuous, but was present throughout the string. It is not known how much scale was present but was removed in the process of killing the well with water and mud prior to pulling the tubing.

Analyses made of the water produced by wells on which silicate treatment was used indicate a general reduction in the iron content of the water produced, but the iron contents vary so widely that it is impossible to draw an accurate conclusion as to the amount of protection being afforded. In some cases, it is found that the iron content is 5 to 20 parts per million as much as two months after the injection. In many cases, the iron content does not drop below 40 or 50 parts per million. Immediately after treatment, the iron content is usually high because of the scouring action of the chemical.

Wellhead Assemblies

Wellhead equipment is no longer considered a problem because component parts made of corrosion resistant materials are available at reasonable costs. The NACE spool tests and tests in actual service show that steel containing 11 to 13 percent chromium, 18-8 type stainless steel, Monel, Stellite, and Hastelloy give trouble-free service. It is considered good practice in new fields where the corrosion level has not been determined to use these materials in the master valve and for flange ring gaskets. Other pieces of equipment can be replaced fairly easily if conditions warrant. These same materials can be used in chokes, regulators, and safety valves if employed in the tubing strings. Using ordinary steel in choke

assemblies is often desirable at first because choke beans can be used as "coupons" to determine the degree of corrosion. The scale formed by sodium silicate treatments protects wellhead equipment except chokes. Special materials are not needed in wellheads on oil wells such as at Bayou Sale, because of protecting paraffin deposits.

Flow Lines

Internal corrosion of flow lines and other surface equipment in condensate service has been found to be erratic, but in general a corrosive condition exists. Black pipe is used and can be protected with chemicals and if chemicals are used to protect the tubing, protection of the surface lines is also obtained. Where corrosion resistant tubing is used, the corrosion of flow lines is often accelerated.

Identifying Corrosive Wells

The use of caliped surveys in tubing is a general practice in order to determine the location, severity, and rate of corrosion, and most well operators have surveys made annually on all but their least important wells. Surveys are sometimes made more often than once a year while studying the effect of chemical treatments. Surveys made immediately after a well is completed to establish a "base line" are believed to have little value because the industry has learned to interpret charts so as to differentiate between mill defects and corrosion pits. Frequently, surveys made during the first six months that a well is producing indicate that corrosion has not started while subsequent surveys show a rather high rate of corrosion. This has never been explained satisfactorily but is probably due to materials present that act as neutralizing agents for a while or it is due to the fact that the intercrystalline attack takes a while to become apparent.

The iron content of fresh water produced from condensate wells is a fairly reliable indication of the severity of corrosion, but it is not entirely so. Care must be taken to obtain representative water samples. If the iron content is less than about 40 parts per million, corrosion is unimportant. If it is above 150 parts per million, corrosion is of economic importance. When it is between 40 and 150 parts per million, the corrosion should be considered serious unless further investigation proves otherwise.

The carbon dioxide content of the gas appears to be a good relative index to the severity of corrosion when other factors are similar. Where the carbon dioxide content is 0.2 percent or less, corrosion is not a problem. In fields in which more than one reservoir produces, the corrosion varies directly with the carbon dioxide content.

Summary and Conclusions

As a result of studies by individuals and groups, the corrosion problem in condensate and deep oil wells is fairly well understood. It is recognized that each field and often each well is a different problem. The most economical solution of individual field problems can be arrived at only after studying the cor-

rosion rates, the equipment failures, and the success of corrosion preventive measures tried in that particular field.

Successful corrosion preventive measures have been found for condensate wells where tubing is not set on packers.

The use of plastic-coated tubing is an economical solution to the problem in deep flowing oil wells.

Several methods of preventing corrosion of tubing where it is set on a packer in condensate wells are in the trial or experimental stage of development. To date, none has been established as being economical in all fields. The jointing problem requires further study. Steel containing 9 percent nickel appears to be a suitable material, but at present prices it will have to give more than 10 years of trouble-free service to be economical in the average corrosive well. Nickel-plated steel looks feasible. The use of black tubing protected by sodium silicate treatments looks promising.

The corrosion problem in condensate fields appears to be about one-half solved. The other one-half will have to come from further study of present methods of controlling corrosion and continued cooperative effort. Additional chemical and metallurgical developments appear desirable.

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The expression of opinions about or the addition of information to that contained in technical articles will advance the interests of NACE and make CORROSION more valuable to the membership.

The Role of Polarization
In Electrochemical Corrosion*

By R. H. BROWN,* G. C. ENGLISH** and R. D. WILLIAMS**

Introduction

A DISCUSSION of the polarization of electrodes must necessarily be predicated upon knowledge of the true or thermodynamic potentials of those electrodes, since any departure of a potential of an electrode from the thermodynamic potential is concerned with polarization. Figure 1 shows how the thermodynamic potential of a number of metals varies with the activity of the ions of these respective metals in solution.

In a rigorous thermodynamic treatment of electrode potentials it is necessary to use the activities of the ions, that is, their thermodynamic concentrations rather than the gravimetric concentrations. The activity of the ion is related to the gravimetric concentration by the equation $A = \alpha C$ where A is the activity in moles per 1000 grams of water, C is the concentration in moles per 1000 grams of water and α is the activity coefficient which in infinitely dilute solutions has a value of unity. Since we may simplify the discussion without sacrificing exactness of the principles, the activity will be used throughout the remainder of the discussion as being equal to the concentration; that is α will be considered as being equal to one. From Figure 1 it is possible to state, knowing the concentration of ions in solution, the potential below which a gas or metal cannot be plated out or the potential above which the gas or metal can not be converted into ions in the solution. For example, if a piece of zinc in a solution of its ions at a concentration of 1×10^{-7} molal has a potential of —1.2 volts, the reaction $Zn^{++} + 2e^- \rightarrow Zn$ will not occur. If, on the other hand, the potential of the electrode is —1.4 volts, the reaction $Zn \rightarrow Zn^{++} + 2e^-$ will not occur. The first reaction is the reduction reaction or cathodic reaction, and the second is an oxidation reaction or an anodic reaction. The overall driving force of a cell is the difference in potentials for the anodic and cathodic reactions.

The reactions in Figure 1 with the exception of $1/2H_2 \rightarrow H^+ + 1e^-$, occur in most cases of corrosion as anodic reactions, although in the case of some metals under cathodic protection they may occur as cathodic reactions. In many cases of corrosion, the hydrogen reaction occurs as a cathodic reaction. However, cathodic reactions involving oxygen are also

Abstract

In its most practical aspects as well as in its fundamental mechanisms electrochemical corrosion is almost always associated with irreversible electrode phenomena. The multitude of factors involved in these phenomena may be defined as electrochemical polarization. Idealized schematic as well as actual polarization diagrams are discussed. Methods of correlating polarization with corrosion data such as weight loss are shown. A method for obtaining the contribution made by the polarization of each electrode reaction to the total polarization observed at an electrode is described along with the implications thereof in the evaluation of the true over-voltage values. In addition, other factors which may fall within a broad definition of polarization are treated. The relationship of the so-called IR drop or true ohmic resistance at metal liquid interfaces to polarization diagrams and to voltage concepts is discussed.
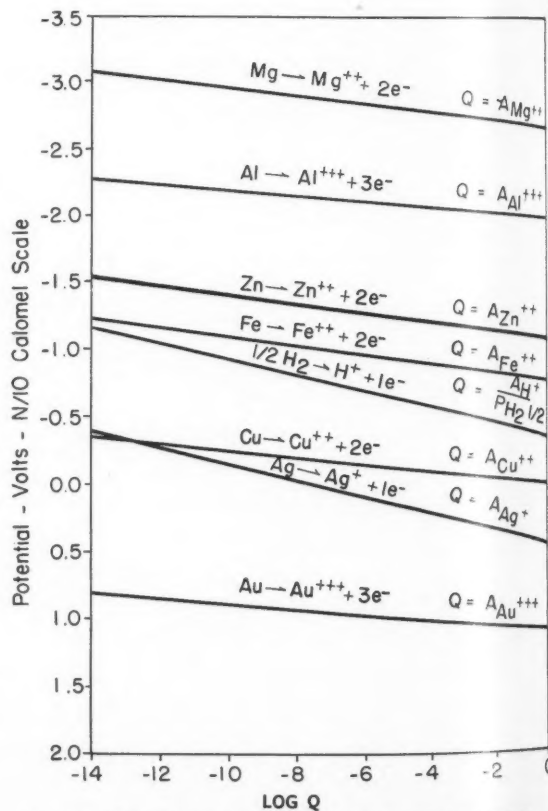
Figure 1—Thermodynamic potentials of metal-metal ion electrodes.
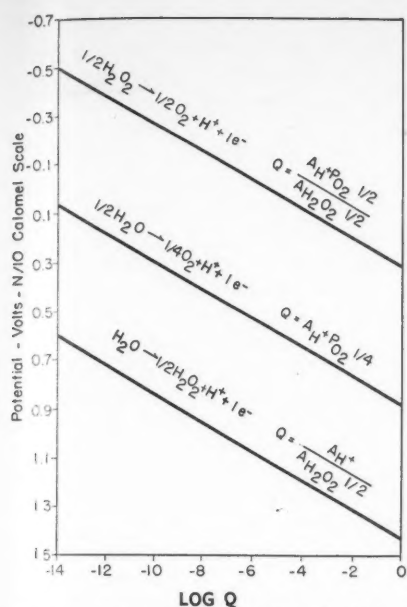
Figure 2—Effect of activities on the thermodynamic electrode potential of reactions involving oxygen.

POTENTIAL OF GRAIN BOUNDARIES AND GRAINS

SOLUTION N/10 KCl   N/10 CALOMEL SCALE
GROSS POTENTIAL = −0.635 VOLTS

ALUMINUM COPPER (4% CU) ALLOY - COLD WATER QUENCHED
AGED 16 HOURS AT 150° C.

Figure 3

important in many corrosion processes. The thermodynamic potentials of three of the more important reactions involving oxygen are shown in Figure 2. Here it must be pointed out that the thermodynamic potential of the reaction $H_2O_2 \rightarrow 2H^+ + O_2 + 2e^-$ is dependent not only upon the concentration of the hydrogen ion, but also upon the partial pressure of oxygen and the concentration of hydrogen peroxide. This point is emphasized because many are prone to disregard those contributing factors which at times may be difficult to evaluate.

When a metal is immersed in a solution it is possible for several reactions to occur, depending upon the composition of the solution and nature of the metal. If there is no interference with the reaction or a loss of products from the system, an equilibrium will be established between the reactants and products and further reaction ceases. Consider a metal such as zinc in a slightly acidic solution of zinc ions which has been freed of all dissolved gas. One of the reactions which, from the energy viewpoint, could occur is

$$Zn + 2H^+ \rightarrow Zn^{++} + H_2 \tag{1}$$
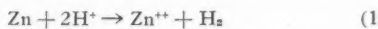
and the reaction should proceed until equilibrium is established. It is well known that this reaction, despite a favorable energy relation, does not proceed to equilibrium. It is said that the reaction is polarized.

Hence, when a single electrode of a metal such as zinc is in solution, at least two reactions must be considered, which means in turn that two thermodynamic potentials must be involved, that is E_{Zn} and E_H. Inasmuch as two different potentials cannot simultaneously exist on the metal, the difference in the two potentials E_{Zn} and E_H as shown in Figure 1 must be reconciled. Since the measured potential corresponds closely to the E_{Zn} calculated from thermodynamics, the hydrogen reaction is polarized.
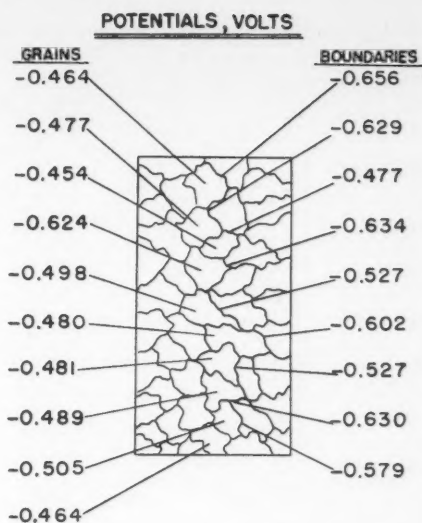
Thus, it may be concluded that:
1) When the measured potential of an electrode corresponds to the thermodynamic potential for one of the possible reactions, all other possible reactions are polarized.
2) When the measured potential of an electrode does not correspond to the thermodynamic potential for any of the reactions that are possible at the electrode surface, all of the reactions are polarized.

From the foregoing, electrochemical polarization can encompass those phenomena that prevent an electrochemical reaction from attaining its equilibrium state in a thermodynamic sense. The prevention of a reaction at an electrode surface attaining its thermodynamic potential when current is flowing to or from the surface, is usually considered as being manifested by a back emf. For example, if the reaction $H_2 \rightarrow 2H^+ + 2e^-$ fails to reach electrochemical equilibrium and, as a consequence, the measured potential of the electrode differs from that corresponding to its thermodynamic potential, the electrode is said to be polarized and the difference in potential from the thermodynamic value has been termed overvoltage.

In the actual measurement of an electrode potential, voltage effects, other than those created because equilibrium is not attained, may be included. When current from any source is flowing to or from an electrode surface, voltage drops may occur across ohmic resistances at the metal-liquid interface. Such voltage drops are included in most polarization measurements.

When an electrode is polarized cathodically, the value of the potential moves in an anodic direction,
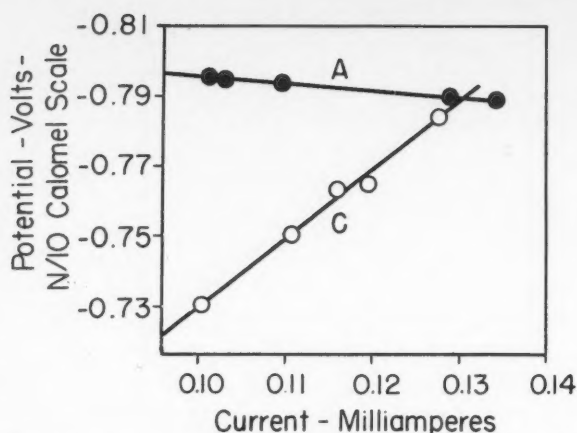
Figure 4—Experimental local polarization curves for iron in N/20 potassium chloride illustrating cathodic control.
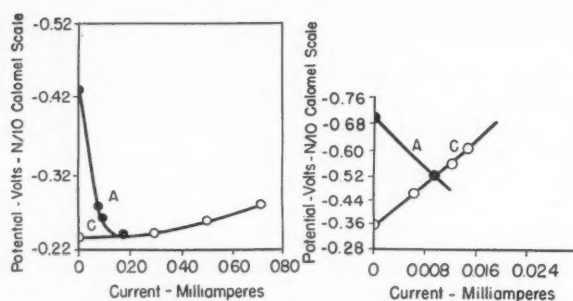
Figure 5—Experimental local polarization curves for 18 Cr 8 Ni stainless steel in 150g sodium chloride and 0.84g ferric chloride per liter illustrating anodic control.

Figure 6—Experimental local polarization curves of aluminum in N/10 potassium sulfate and 0.3% hydrogen peroxide illustrating mixed control.
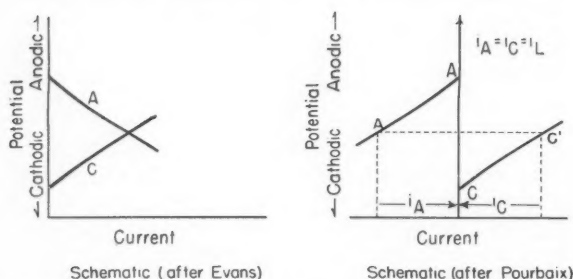
Figure 7—Two types of schematic polarization diagrams illustrating mixed control.
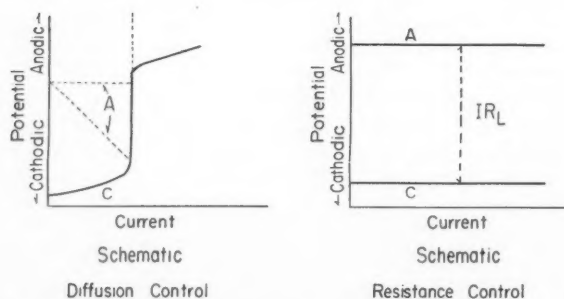
Figure 8—Polarization diagrams showing diffusion control and resistance control.

and when it is polarized anodically, the value of the potential moves in a cathodic direction.

This article is concerned primarily with polarization as it affects corrosion or corrosion velocity. The corrosion referred to is the electrochemical corrosion of metals and alloys occuring whenever the latter are placed in conducting media.

In general, if a metal is placed in a good conducting solution, composed partly of its own ions, for instance, current will flow between differential potential areas on the surface of the metal even though the electrode half-cell reaction be considered reversible, and polarizing phenomenon will be present adjacent to the metal surface and in the vicinity of the differential potential areas due to the irreversible effects of resistance, overvoltage and polarization as discussed above. That these areas exist is well known. An important experiment adequately demonstrating this phenomenon was that reported by Dix,[1] in which actual potential values at various areas on an aluminum-copper alloy were measured. See Figure 3.

Types of Control

If the irreversible effects at the cathode areas influence the corrosion velocity while those at the anode areas do not, according to Evans the system is under cathodic control. See Figure 4. The point at which the anodic and cathodic polarization curves intercept is the measured potential, and the current at the intercept is the limiting corrosion current. Conversely, if the irreversible effects at the anode areas influence the corrosion velocity while those at the cathode area do not, the system is under anodic control. See Figure 5. When effects at both the cathode and anode areas affect the corrosion rate, the system is said to be under mixed control. See Figure 6. It is not necessary that these effects be produced at discrete areas as long as the polarization of the respective anodic and cathodic reactions occurs.

An example of the continental or Pourbaix type diagram is shown in Figure 7 since there is a substantial group of electrochemists in the field of corrosion who use this type. No fundamental differences between the Evans and the Pourbaix type diagrams are found, although there may be systems in which one or the other may be used more conveniently. The corrosion current and measured potential in the Pourbaix type diagram are found very simply. The point at which a line drawn horizontally to the current coordinate and intersecting the anodic and cathodic polarization curves is bisected by the potential coordinate, is the measured potential. The corrosion current will be measured directly from the point at which the horizontal line intersects the polarization curve.

In the above examples it was assumed that the resistance of the solutions was low. However, when the resistance of the solution is appreciable, an IR factor must be considered. With increasing resistance the value of the corrosion current will move left from the point of intersection of the anodic and cathodic curves and the corrosion rate will decrease in an amount corresponding to the value of the IR drop.

value of th ... Other factors can also vary with the resistivity of the solution. Such factors as the changes of oxygen concentration with increasing salt concentration may, of course, affect the rate of corrosion so that more than just the IR factor must be taken into account. When the polarization of both the anodes and the cathodes is negligible, the system will be under resistance control as shown in Figure 8.

A well known type of polarization is that in which the flow of current is controlled by diffusion and is often referred to as concentration polarization. Based on Fick's laws of diffusion, the numerical magnitude of the concentration polarization is approximately proportional to the current density when the latter is relatively small. However, as the current is increased and approaches a limiting value that is dependent upon the diffusion coefficient of the ionic species in question and the thickness of the diffusion layer between the electrode and the solution, the numerical magnitude of the concentration polarization increases rapidly. When the current is increased to an extent that the rate of diffusion is insufficient to keep up with the discharge of the ions at the cathode, then the potential will change abruptly to a more negative value until another electrode process can occur. Within relatively broad limits the extent of the anodic polarization will not affect the corrosion current as shown in Figure 8.[2]

Correlation Between Weight Loss and Corrosion Current

The corrosion velocity of a metal corroding in a conducting media is proportional to the current as shown by any of the foregoing diagrams. From Faraday's laws this proportionality is represented by the following equation

$$\frac{\text{weight loss}}{\phi} = ki \qquad (2$$

Where ϕ is a specific unit of time, i is the current as measured over time ϕ and k is a proportionality constant.

The validity of this equation can be examined by comparing weight loss data to polarization data. Evans[3] has tabulated data of weight loss of partially immersed specimens of steel exposed in N/20 KCl solution as affected by varying the width of the specimens and the depth of immersion.

Because the weight loss per unit of time of a specimen of given dimensions is proportional to the corrosion current, a weight loss per unit of time scale on the horizontal coordinate can be used in place of the current scale to construct the polarization diagram. For this construction, the open circuit potential of the anodes and cathodes, and the corroding potential were taken from data of Evans and Hoar[4] for similar specimens exposed in N/10 KCl under the same exposure conditions.

From the work of Evans and Hoar it could be concluded that the slope of the cathodic polarization curve will be a function of the width of the specimen. It may be assumed that the anodic polarization curve will be a function of the local anodic area of the specimen. It has been further assumed that this area is proportional to the total area of the specimen.
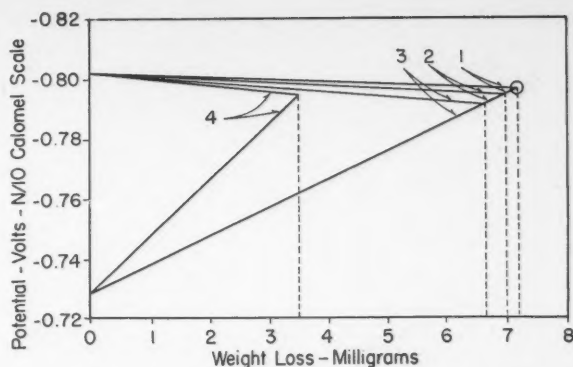
Weight Loss—Milligrams

Sample	Width	Depth	Area	SLOPE		WEIGHT LOSS	
				Anode	Cathode	Measured	Caculated
1	2.4	4.0	9.6	0.006 9.6 / 7.2 9.6	0.068 2.4 / 7.2 2.4	7.2 ± 0.5	7.2
2	2.4	3.0	7.2	0.006 9.6 / 7.2 7.2	0.068 2.4 / 7.2 2.4	6.9 ± 0.5	7.0
3	2.4	2.0	4.8	0.006 9.6 / 7.2 4.8	0.068 2.4 / 7.2 2.4	5.7 ± 0.5	6.7
4	1.2	3.0	3.6	0.006 9.6 / 7.2 3.6	0.068 2.4 / 7.2 1.2	3.9 ± 0.5	3.5

Fig. 9—Construction of polarization diagrams to calculate weight loss resulting from corrosion.

Knowing the corroding potential and the weight loss of a given specimen, the polarization diagram may be constructed as shown in Figure 9. If the polarization curves are straight lines as shown by Evans and Hoar, the polarization diagram may be established by plotting three points. Two of the points are the open circuit potentials of the anodes and cathodes at zero weight loss and the third point is located by plotting the actual weight loss (for example, the actual weight loss of sample 1) against the corroding potential. By joining the open circuit potential of the cathodes with this last point, the polarization curve of the local cathodes is obtained; by similarly joining the open circuit potential of the anodes with the above point, the polarization curve of the local anodes is obtained.

For specimens of other sizes, the slope of the anodic polarization curve will be a function of the area of the sample tested, multiplied by a constant also fixed by the data used to plot the point in Figure 9. The slope of the cathodic polarization curve will be a function of the width of the specimen, multiplied by another constant based on the same data as above. It has been stated that the intersection of the anodic and cathodic polarization curves is the measure of the corrosion current and that the latter is proportional to the weight loss. Construction of the polarization lines having the slopes indicated in the table gives the calculated weight loss directly. The weight losses for samples 2, 3, and 4 predicted from this construction compare favorably with the measured values.

Thus far, no mention of polarization as it applies

to cathodic protection has been made. However, the cathodic polarization curve of any metal and in some instances the point in the cathodic polarization curve at which protection is obtained, may be predicted[5] from the individual local cathodic and local anodic polarization curves.

As shown in Figure 10a the experimental local anodic polarization curve is represented by A. The anode consisted of two pits in an aluminum specimen that were appropriately insulated by methods well known.[6] Line C represents the local cathodic polarization curve. Line C' represents the cathodic polarization curve of the two pits when they are made cathodic by the external current. The cathodic polarization curve of the sample including both the pitted and unpitted areas when external current is applied, can be constructed by choosing any point such as b on line C and drawing a horizontal line, for instance bc, perpendicular to the potential coordinate. The intersection of line bc with the potential axis may be taken as the potential to which the local cathodes have been polarized by the external current i_x. In order to estimate the local action current that is supplied by the local anodes, a curve is drawn by transposing to the left all points of curve C by an amount cb, which is the magnitude of the externally applied current i_x. The intersection of this curve with the local anodic polarization curve at E' is the local anodic current, or corrosion current, with externally applied current i_x. The potential at point E' is the measured potential of the entire specimen for the applied current i_x. Hence a point can be plotted of applied current against the measured potential of the specimen, where the magnitude of the current is

shown by cb and the magnitude of the measured potential is given by E'. For different values of applied current, sufficient points can be obtained to construct the curve shown in Figure 10b. Verification of the graphical construction of the curve of external current versus potential was obtained by applying an external current and measuring the potential of the cathodically polarized specimen. The data obtained in this manner are shown by triangles in Figure 10b.

Complete cathodic protection is achieved when the applied current is of sufficient value to polarize the entire specimen (including IR drops in the metal-liquid interfaces) to a potential corresponding to that of the open circuit potential of the pits or to any point where the cathodic polarization current of curve c' is greater than zero. In many instances this point will be accentuated by a sharp point of inflection in curve C. Particularly is this true of systems under cathodic control or of systems under mixed control but closely approaching cathodic control. Reference to the schematic diagram representing anodic control shows that when the system is under complete anodic control (no cathodic polarization), it is impossible to accomplish cathodic protection.

It may not be immediately apparent that cathodic protection for a metal can be obtained with and without electrichemical polarization. For example, if the measured potential of a metal electrode, when external current I is applied, is determined by the following relation

$$E'_A - E'_C - I_A R_A - I_C R_C = O \qquad (3$$

where E'_A and E'_C are the unpolarized local anodic and cathodic potentials, respectively, the condition

C'- Cathodic Polarization Curve of Pit
A - Anodic Polarization Curve of Pit
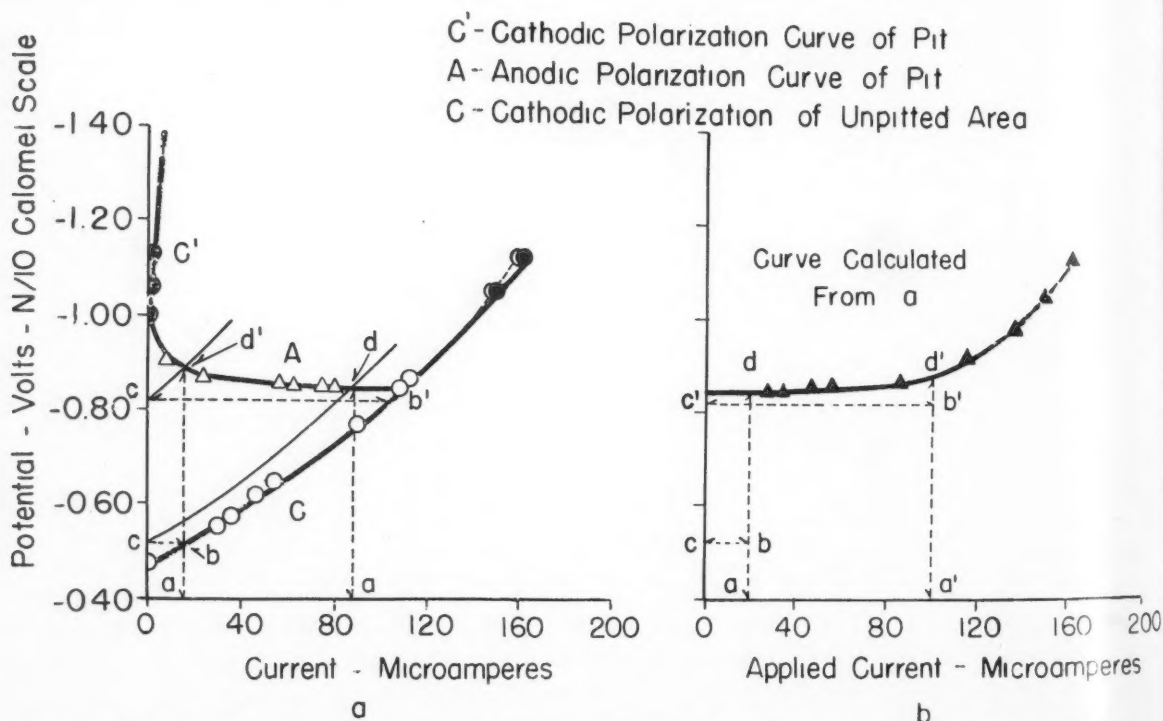C - Cathodic Polarization of Unpitted Area

Figure 10—Construction of the cathodic polarization curve of an aluminum specimen from the experimentally obtained local anodic and local cathodic polarization curves.

for achievement of cathodic protection is that $I_A = O$ and hence for this condition

$$E'_A = E'_c + I_c R_c \qquad (4$$

For complete protection to be achieved, the unpolarized potential of the local cathodes plus the product of the ohmic resistances at the local cathodic metal-liquid interfaces multiplied by the applied current, must equal the open circuit unpolarized potential of the local anode area. Therefore, it is possible to achieve cathodic protection without electrochemical polarization having occurred. In some cases the measured potential of the metal electrode is determined by the relation

$$(E'_A - \Delta E_{AP}) - (E'_c + \Delta E_{CP}) = O \qquad (5$$

where E'_A and E'_c are the local anodic and cathodic potentials, respectively; ΔE_{AP}, the electrochemical polarization of the local anodes, is equal to some function ϕ_A of $\frac{I_A}{Area_A}$; ΔE_{CP}, the electrochemical polarization of the local cathodes, is equal to some function ϕ_c of $\frac{I_c}{Area_c}$. The condition for attaining cathodic protection is again that $I_A = O$, hence

$$E'_A = E'_c + \phi \left(\frac{I_c}{Area_c} \right) \qquad (6$$

Thus, cathodic protection may be attained with or without the occurrence of true electrochemical polarization.

Experimental Determination of Local Anodic and Cathodic Polarization Curves

The advantage of knowing the shape of the local anodic and cathodic polarization curves, and therefore the local cell current, in any corrosive system is indeed apparent. Unfortunately, past methods of obtaining the information necessary for the construction of these important curves have been limited to cases where the local anodic and cathodic elements could be isolated or where the currents could be calculated from external polarization curves and either weight loss data[7] or volumetric measurements of hydrogen gas consumption.[8] Recently, however, a few preliminary experiments have been made which in principle appear to provide a solution to some of the cases where it is not possible to isolate the local anodic and cathodic elements.

The problem of determining the local current may be resolved to the solution of the following equation, providing the potential of the electrode remains constant.

$$I_x + I_L \rightleftharpoons \Sigma I_c \qquad (7$$

where I_x is the externally applied current, I_L is the local cell current and ΣI_c is the sum of all the currents due to the total number of reduction reactions occurring at a cathode when the latter is cathodically polarized.

Measurement of the terms included in the quantity ΣI_c presents a most difficult problem and may only

be feasible by employing indirect methods. The possibility of measuring indirectly the components of ΣI_c is not a new idea, but previous to some recent work of Dr. Paul Delahay[9] little had been done to evaluate accurately any of the currents in question. By means of the polarographic method Delahay was able to follow the disappearance of oxygen with time, the potential of the specimen being constant over that period of time. Assuming the oxygen reduction reactions to be

$$O_2 + 2H^+ + 2e^- \rightarrow H_2O_2 \qquad (8$$

and

$$O_2 + 4H^+ + 4e^- \rightarrow 2\,H_2O \qquad (9$$
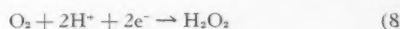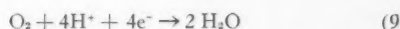
or mixtures of these reactions, he calculated by means of Faraday's laws the current corresponding to the rate of consumption of oxygen by electrochemical reduction for several potential values.

By combining the techniques developed by Van Rysselberghe[10] and Delahay[9] and with some slight modifications by the authors, the local cell current for a 2S aluminum specimen of 6 cms² area, immersed in a solution one molar in potassium chloride, and containing 2.2×10^{-4} moles per liter of oxygen and 6.84×10^{-4} moles per liter of sulfuric acid, has been experimentally determined in a 37 ml. air tight glass container fitted with a magnetic stirring device. The apparatus is shown schematically in Figure 11. At each potential the amount of hydrogen ion and oxygen consumed and the amount of hydrogen peroxide present were determined by means of a polarograph for exposure periods of 20, 40 and 60 minutes, each period requiring a new specimen and a new solution. Each point was determined three times, thus using nine specimens to determine an average curve.

With the above information it is possible to calculate for each period of exposure and for each potential the total amount of hydrogen ion consumed.
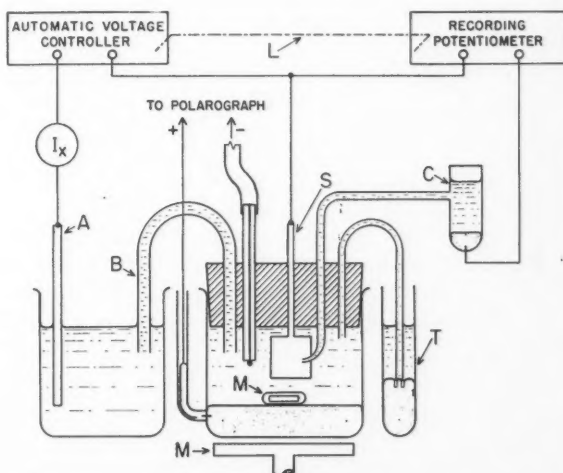
Figure 11—Apparatus for polarographic study of cathodic polarization processes: A—platinum anode; B—agar-KCl salt bridge; C—N/10 calomel reference electrode; I_x milliammeter; L—electrochemical linkage between potentiometer and voltage controller; M—magnetic stirrer; S—aluminum specimen.

This includes the amount of hydrogen ion consumed by the reactions

$$2H^+ + O_2 + 2e^- \rightarrow H_2O_2 \quad\quad (10$$

$$4H^+ + O_2 + 4e^- \rightarrow 2H_2O^* \quad\quad (11$$

$$2H^+ + 2e^- \rightarrow H_2 \quad\quad (12$$

If hydrogen ion is not consumed by any other reactions, then the difference between the total hydrogen ion consumed and that consumed by the reactions (10) and (11) is the hydrogen ion consumed by reactions (12).

A plot can be made of the total hydrogen ion that is consumed against time of exposure at constant potential. From the slope of this curve at the initial application of external current (that is, at zero time), the total current resulting from the cathodic reduction of reactions involving hydrogen ion was calculated and has been plotted in Figure 12. Assuming that hydrogen ion is consumed by only by reactions (10), (11), and (12) a plot was made of the hydrogen ion consumed by reactions (10) and (11). As was done in the case of the total hydrogen consumed, the current resulting from reactions (10) and (11) was calculated from the slope at the curve at zero time. This current is also shown in Figure 12. The difference between the total cathodic current and that current resulting from oxygen consumption reactions, (10) and (11), gives the current resulting from reaction (12), $2H^+ + 2e^- \rightarrow H_2$. The current attributed to reaction (12) is only valid in this experiment if the above three reactions are the only ones involved in the cathodic processes. In general, this appears to be a valid assumption, but the possibility of other cathodic reactions must not be neglected. Indeed, polarographic studies have shown that when hydrogen peroxide is formed in presence of dissolved carbon dioxide, percarbonate type ions are formed and have an appreciable affect on the corrosion rate of some metals.[10] In Figure 13 are shown some possible therm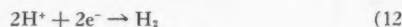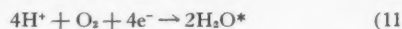odynamic potentials at which the reduction of percarbonic acid could consume hydrogen ion at the cathode. These estimated potential values indicate that such a reaction occurs at relatively low cathodic potentials.

In the general case a consideration of all cathodic reactions occurring in a system becomes very involved because of the large number of possible reactions. For example, in the above experiment the solution was 6.84×10^{-4} molar in sulfate ion. It is shown in Figure 13 that the thermodynamic potential of the reduction reaction at which sulfate ion consumes hydrogen ion at the cathode is at a relatively high potential and is not as thermodynamically probable as the percarbonate reaction. Although it is not believed that the sulfate ion was operative in the cathodic processes in the above experiment, further

* It is not improbable that reaction (11) can proceed by at least two other mechanisms, namely,

$$2H^+ + O_2 + 2e^- \rightarrow H_2O_2$$
$$2H^+ + H_2O_2 + 2e^- \rightarrow 2H_2O$$

or

$$4H^+ + 2O_2 + 4e^- \rightarrow 2H_2O$$
$$2H_2O_2 \xrightarrow{\text{catalyst}} 2H_2O + O_2$$
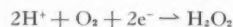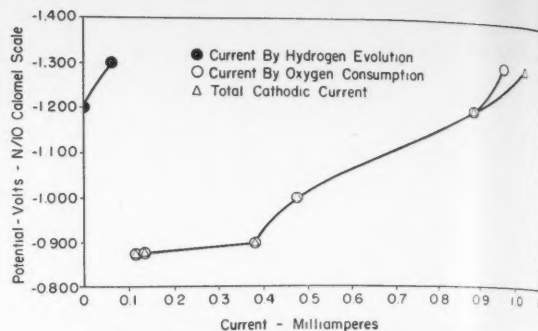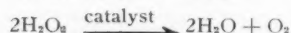
Figure 12—Cathodic polarization curve produced by hydrogen ion reduction, by oxygen reduction reactions, and the sum of hydrogen ion and oxygen reduction on a 2S aluminum specimen 6 cm² in area. The solution was one molar in potassium chloride, 2.2×10^{-4} molar in oxygen and 6.84×10^{-4} molar in sulfuric acid.
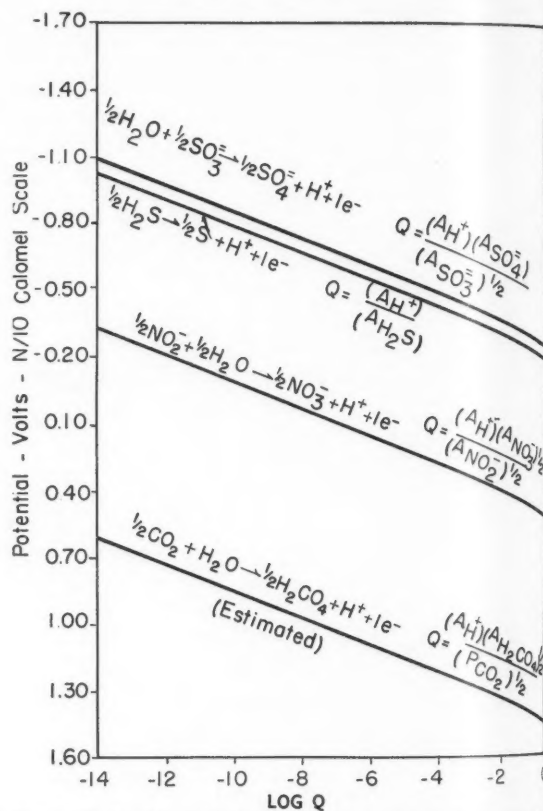
Figure 13—Possible cathodic reactions encountered in corrosion processes.

work should include investigation of this possibility. From Figure 13, the reduction of nitrate ion would have been possible, if this ion had been present in the solution. Regardless of other ions that could be involved in the cathodic processes in the above experiment, it does not appear that any of the possible reactions would have occurred without consuming hydrogen ion. Therefore, the total cathodic current as calculated from the rate of consumption of hydrogen ion is the total cathodic current at any given value of external current required to polarize the aluminum specimen to a given potential. Consequently, from equation (7) the difference between

the total cathodic current and the externally applied current will be the local anodic current as shown in Figure 14. It is observed that if the specimen is polarized to slightly over 900 millivolts on the N/10 calomel scale that the local anodic current is at a very low value. This shows that cathodic protection is essentially complete on aluminum (2S-H14) in this solution if the potentials are more anodic than 900 millivolts. This also serves to emphasize that the local cell action plays an important role in determining the shape of polarization curves.

The above method of determining the local anodic and cathodic curves requires the experimental determination of the total cathodic polarization curve and the resultant calculation of the local anodic current, whereas the weight loss method as used by Petrocelli[7] requires the experimental determination of the local anodic current and the resultant estimation of the total cathodic polarization curve. The limitations of the weight loss method have been discussed elsewhere.[11]

IR Drops

Previously in this paper reference has been made to the inclusion in polarization determinations of the IR drop across ohmic resistances at metal-liquid interfaces. Methods for determining the magnitude of these IR drops have been advanced by Pearson[12] and Holler.[13]

The magnitude of these IR drops has been determined on the cathodically polarized electrode systems shown in Figures 15, 16, and 17 using an apparatus patterned after the Pearson bridge which is shown schematically in Figure 18. After considerable experimental work with models composed entirely of metallic conductors and with several electrochemical models it was established that Pearson's proposed electrical analogy of an electrode surface was essentially correct. The data shown in Figures 15, 16 and 17 indicate that the IR drops across metal-liquid interfaces during cathodic polarization vary to a marked degree, depending upon the nature of the electrode system. This means that the electrochemical polarization of some of these electrode systems is not as great as is generally assumed. For example, it is observed that mercury in contact with a solution saturated with mercurous chloride does not show

Figure 15—Cathodic polarization curves of zinc in 0.2 molar sodium chloride solution and in 0.1 molar zinc sulfate solution with and without IR drops at metal-liquid interfaces included.
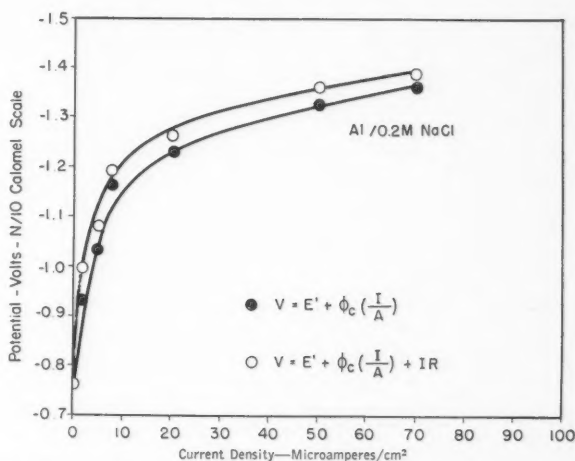
Figure 16—Cathodic polarization curves of aluminum in 0.2 molar sodium chloride solution with and without IR drops at metal-liquid interfaces included.

Figure 14—Calculation of the local anodic corrosion current from the differences between the total cathodic polarization curve and the applied cathodic polarization curve of a 2S aluminum specimen 6 cm² in area. The solution was one molar in potassium chloride, 2.2 x 10⁻⁴ molar in oxygen and 6.84 x 10⁻⁴ molar and 6.84 x 10⁻⁴ molar in sulfuric acid.
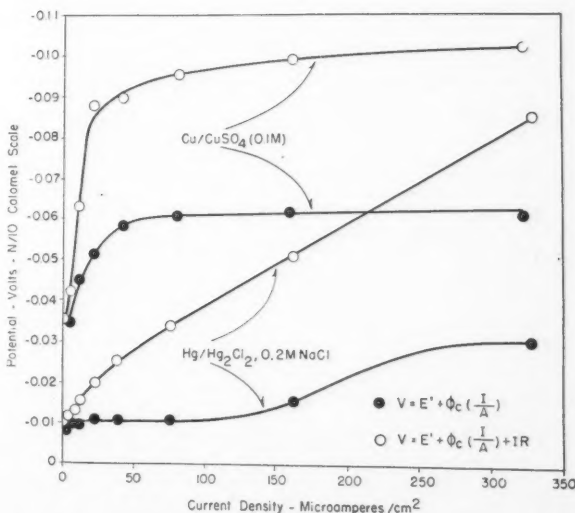

Figure 17—Cathodic polarization curves of mercury in saturated mercurous chloride solution and of copper in 0.1 molar copper sulfate solution with and without IR drops of metal-liquid interfaces included.
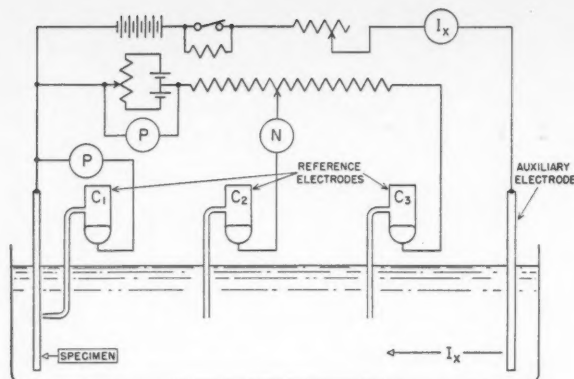
Figure 18—Pearson bridge circuit for elimination of IR drops from electrode potential measurements: C_1, C_2, C_3, — N/10 calomel reference electrodes; I_x — ammeter; N—vacuum tube voltmeter for null detection; P—potentiometer.
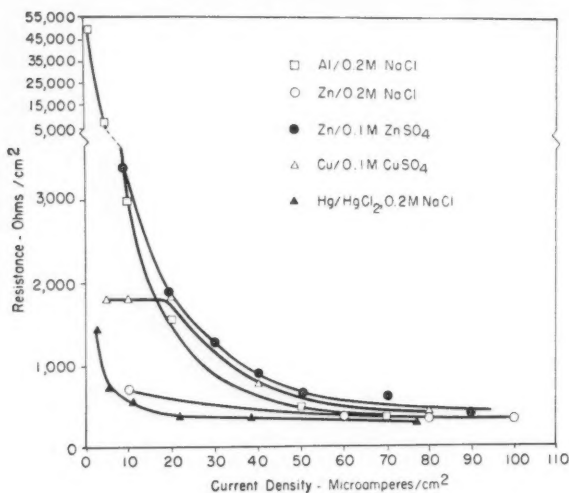
Figure 19—The effect of current density on the resistance per unit area of several electrode systems.
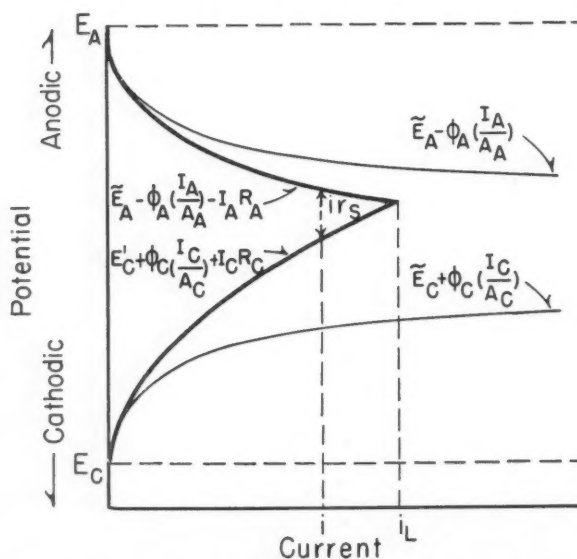
Figure 20—Schematic diagram summarizing the role of polarization in corrosion.

electrochemical polarization at low currents but the effects of the ohmic resistances are appreciable. The effect of current density on the resistance per unit area of several of these electrode systems is shown in Figure 19. First, it is to be noted that the ohmic resistance is highest at low current densities. As might be expected, the resistance per unit area of aluminum is greater than that of metals such as zinc. Secondly, it is to be noted that the IR drop will be of different magnitude for the same metal electrode in various electrolytic solutions.

Summary

Figure 20 represents an attempt to show schematically the role and the complexities of polarization in the corrosion of metals. Point E_A may be taken to be the thermodynamic potential of the anode areas and reactions, and E_C may be taken to be the thermodynamic potential of the cathode areas and reactions. If no voltage effects other than those represented by the reversible or thermodynamic potentials occur, the corrosion current would be determined by the difference in potential divided by the resistance of the electrolyte path between them.

However, voltage effects are produced at the metalliquid interfaces and they reduce the voltage available to drive current through the corrosion cell circuit. One of these effects is the electrochemical polarization of the anode and cathode reactions and is shown schematically by curves $\widetilde{E}_C + \phi_C\left(\frac{I_C}{A_C}\right)$ and $\widetilde{E}_A - \phi_A\left(\frac{I_A}{A_A}\right)$. This electrochemical polarization may involve several reactions. In addition voltage drops across ohmic resistances at the metal-liquid interfaces are produced by the flow of current. These effects further retard the corrosion current and are shown schematically in curves $\widetilde{E}_A + \phi_A\left(\frac{I_A}{A_A}\right) - I_A R_A$ $\widetilde{E'}_C + \phi\left(\frac{I_C}{A_C}\right) + I_C R_C$, where the resulting IR drops have been added to the electrochemical polarization terms. If the resistance of the liquid is negligibly small, the current flow resulting from corrosion action is given by the intercept of these last two curves, that is i_L. This value of current may be taken as the maximum current which can flow in t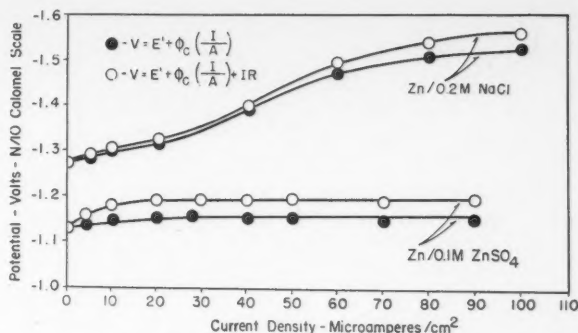he corrosion cell. However, since the liquid path has appreciable resistance, r_s, the current actually resulting is shown as i where the polarization potential of the local anodes and cathodes are separated by an amount equal to the ir_s drop through the solution.

Acknowledgement

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Corrosion in Sulfur Production;
The Use of An Alloy Protective Coating*

By NORMAN HACKERMAN* and D. A. SHOCK**

Introduction

INTERNAL CORROSION in the producing tubing in the Frash process for mining sulfur has long been recognized as one of the operating problems in the production of sulfur. It is evident that the presence of such materials as sulfur, sulfur compounds, water, dissolved salts, and air as well as the elevated temperatures of operation provide severe corrosion conditions. The most severe corrosion is generally found on the interior of the sulfur producing tubing and the exterior of the tubing which supplies the air to lift the molten sulfur to the surface. Because water, air, and dissolved salts contact only these surfaces usually such high rates may be anticipated there. Inspection of tubing removed from producing wells showed that both severe general corrosion and pit penetration was occurring. Also it was determined that sulfides were being formed.

There was no information available on which to base an estimate of the rates of attack during the various phases of production nor could the observed types of corrosion be explained simply from inspection of exposed equipment. West[1] studied the corrosion rates of several ferrous and non-ferrous alloys in sulfur. He showed that the rate of attack increased markedly in the presence of water. Fanelli[2] showed that the addition of elemental halogens to these systems, especially chlorine, accelerated the corrosion rate. Aside from these papers, very little was found in the literature. Accordingly, a program of investigation was undertaken to develop this information. An earlier portion of this work has been reported previously.[3]

Abstract

Apparatus was devised and installed in the field which permitted measurements of the rates of corrosion during the various phases of sulphur production. From these studies it was definitely established that severe corrosion occurred only when water and molten sulphur were in contact with the steel surfaces together. This was corroborated in the laboratory where it was found that the corrosive effects due to molten sulphur alone were negligible while those due to the water alone were only little more serious. When sulphur and water came into intimate contact with the steel together, however, the corrosion rate increased manyfold.

During the course of these studies sections of galvanized pipe normally used in the wells were found to resist the corrosive medium better than might have been expected on the basis of the standard electrode potentials of zinc and iron and the acidic character of the water, sulphur, air mixture. It was found that in salt solutions the potentials of the coating following exposure in a well was cathodic to unexposed mild steel. Analysis of the coating showed a relatively high aluminum and magnesium content and was believed that the exceptional corrosion resistance of the galvanizing was due to these materials. Coatings containing zinc, magnesium, and aluminum were prepared and these were found to be uniformly more corrosion resistant than the galvanizing alone, both in laboratory and in field experiments. Effectiveness of the coating improved with increased concentration of the light metals. Difficulties in preparing alloys of higher concentrations and in obtaining adherent coatings have thus far imposed definite limitations on the useful alloy range.

Field Apparatus and Procedures

Since the first objective was to study the corrosive conditions existing in a producing sulfur well, a modification of a field exposure unit which had been used by this laboratory in condensate well corrosion studies[4] was made. The unit, shown in cross section in Figure 1, consisted of a 20-foot section of steam jacketed 3-inch line which was set in the flow line of a producing well. A bypass line was provided so

that coupons could be inserted or removed while the well was producing. Collars were welded into the pipe section at approximately 8-inch intervals thereby providing for 30 coupons. The coupons were 3″ x ¾″ x 1/16″ strips and were held in the flow stream by bolts which passed through a slit rod. The latter was welded to a plug which fitted the collar.

The coupons were shipped to and from the field in desiccators which were simply 4 or 5-inch pipe nipples, capped on either end. Moisture was held to a minimum in the desiccator by inserting a small bag of silica gel. A thick coating of sulfur left on the coupons after exposure also gave protection (see below).

Coupons of SAE 1020 steel or coated SAE 1020 steel were exposed. After cutting to size the surfaces were abraded on a belt sander to remove all mill scale. This operation was carried out slowly enough to keep the coupons from overheating. The coupons were then numbered, weighed, and shipped to the field, in the pipe desiccators, for installation.

After exposure the coupons were removed by backing out the plug, slipping an envelope over the coupon, and then unbolting the coupon. These were then inserted in the desiccator and shipped to this laboratory.

Sulfur adhered to the coupons on withdrawal from the flow line. It was found that the sulfur coating served as a protective layer and also held the corrosion products in place during transportation of the coupons from the field.

The sulfur had to be removed before laboratory evaluation work of the coupons could be undertaken. It was found that it could be removed successfully by placing the coupon in a still in which CS_2 was refluxing. The coupon was placed so that the CS_2 condensate dropped directly on it. After a single treatment there was generally some sulfur left on the coupon, particularly if the corrosion product was

thick. To remove the remaining sulfur, the coupons were heated at 90° C for one hour and then subjected to the refluxing CS_2 once again. Presumably the heat treatment provided more of the CS_2-soluble form by increasing the rate of recrystallization of the amorphous material formed on rapid cooling.* The coupon was then weighed, the surface studied, and the corrosion products identified were possible.

The field apparatus was used first to obtain data on the corrosion behavior during a cycle of production. A production cycle is considered as consisting of three general periods: First, the boost period when hot, high pressure water is pumped into the well to melt the formation sulfur and fill the lines; second, the production period when the molten sulfur is lifted by air to the surface; and third, the blow period in which the sulfur pool has been pumped down to such a point that water enters the tubing and on reaching the lower pressure near the surface flashes to form steam. While these periods are not always clearly defined and need not necessarily occur in sequence, the combination delineates the type of exposures to be expected. The relative length of time of each period is variable, depending on the individual wells. In general, however, the boost and blow periods last for a matter of hours, whereas the sulfur production period may possibly cover several months.

Figure 2 shows the coupon corrosion rates determined on a well for a complete cycle. Two of the 30 coupons originally in the field exposure unit were removed each day of a fifteen day period. The well was in operation at the start of the test so that the first five days represented a sulfur producing period. On the fourth day, the well stopped pumping sulfur. On boosting for two and a half hours, it was restored to sulfur production which continued until the ninth day. On the tenth day it was boosted again and produced sulfur until it blew on the twelfth day. A seal was established on the thirteenth day and normal sulfur production continued to the end of the test.

By plotting a weight loss *vs.* time curve for the coupons removed and comparing the operating data, it was evident that the corrosion rates for the various operating periods were quite different. Corrosion rates during sulfur-producing periods were comparatively small but during the times of water contact increased greatly. Straight lines drawn to give the average slopes, show for the first boost period, 0.588 IPY**, for the intermittent period, 0.084 IPY, and for the blow and final boost, 3.175 IPY.

Coupon corrosion during a period of fifteen days of continuous sulfur production in another experiment is shown in Figure 3. The curves represent the weight changes of the coupons after they were desulphured and after descaling. Of course, incomplete removal of sulfur introduces relatively large errors in the desulphured weights when the corrosion rate is low since the weight of scale is slight. However, the lower curve of Figure 3 was included merely to indicate an order of magnitude. In general as removed and descaled curves together are useful in showing scale thickness variations. The relatively
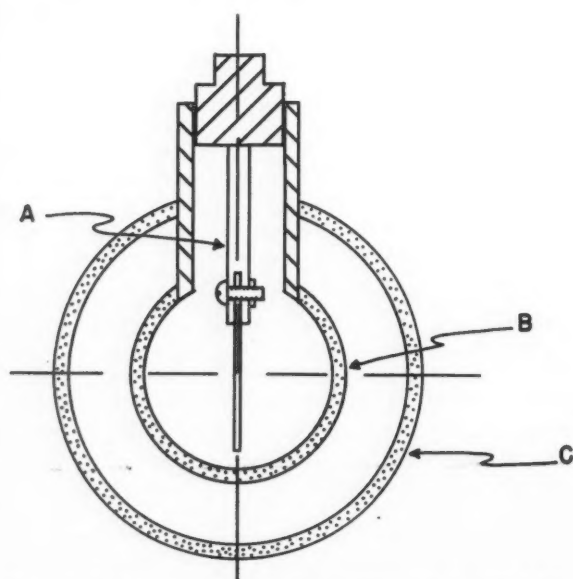

Figure 1—Section through collar of field exposure unit. A—coupon holder and coupon; B—3″ producing tubing; C—steam jacket.

* The $S\mu$ portion of the amorphous solid is not soluble in CS_2.
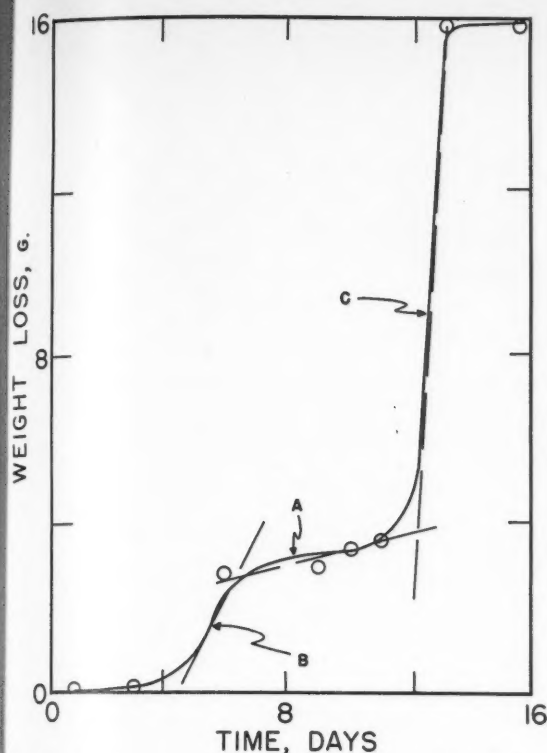** Inches penetration per year.

Figure 4—Reaction rate curve from steel coupons exposed to well fluids A—normal production, IPY=0.08; B—boost, IPY=0.59; C—blow, IPY=3.18.

flat curves indicate that after a surface layer is formed, there is practically no penetration of the metal. Thus at the end of fourteen days the slope of the curve gave a rate of less than 0.0001 IPY. Since no evidence of pits was found this value is the uniform penetration rate. A relatively thin uniform coating was found on the coupons by microscopic examination. This was shown to be an iron sulfide.

The corrosive conditions during a boost period were studied by boosting a well after a series of coupons had been exposed to normal sulfur flow.
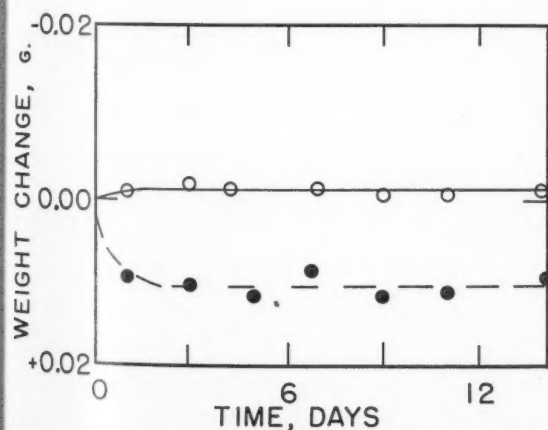
Figure 3—Reaction rate curve from steel coupons exposed to well fluids during normal production only. ●—with scale (sulfur removed); O—descaled.
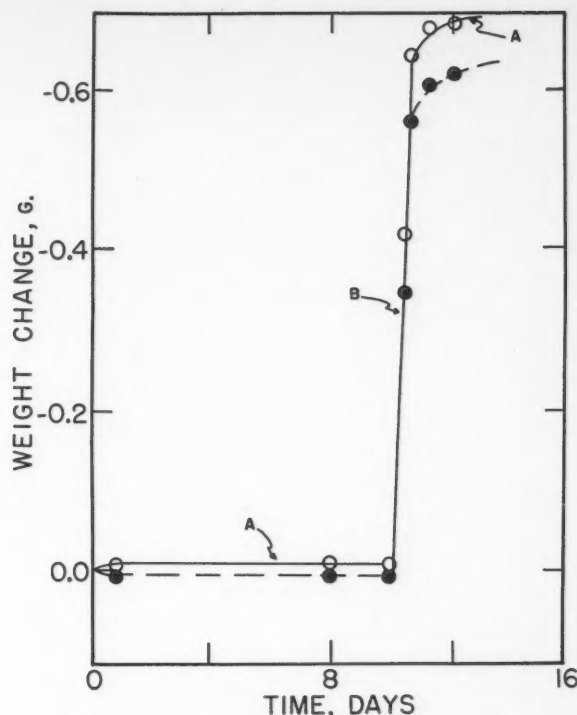
Figure 4—Reaction rate curve from steel coupons exposed to well fluids with particular attention on boost period. A—normal production; B—water contact period. ●—with scale (sulfur removed); O—descaled.

Figure 4 shows the results obtained for the test. As found in the previous experiment the rate of attack during the sulfur production period was negligible. In studying the boost period, coupons were removed at 9:45 am before the boost began, at 11:50 am when the boost was nearly completed, and at 12:45 pm when the well had sealed and was pumping intermittent slugs of water. Normal sulfur flow then continued and coupons were removed during each of two additional days. Both removed and descaled values are shown in Figure 4.

It is evident that the high rate of attack takes place specifically during the water contact time. The divergence of the curves in the period after water contact is due to the thick scale which was formed on the coupon. Under the microscope the surface was found to be generally roughened but not pitted.

The overall corrosion behavior reflected by the coupon study was observed on an operating well in another exposure over a period of 240 days. Figure 5 shows the weight losses of the coupons taken from the coupon holder during this time. Several boost and blow periods occurred during the first 60 days of test and high rates of attack are evident. A long period of uninterrupted sulfur production (165 days) followed with little additional penetration. Just before the well started producing slugs of water, the air line perforated and was replaced. During the intermittent production of water, the coupons underwent continual accelerated attack. Operation of the well was discontinued during this period.

The slow rate of attack during sulfur production periods is again shown by the very low penetration
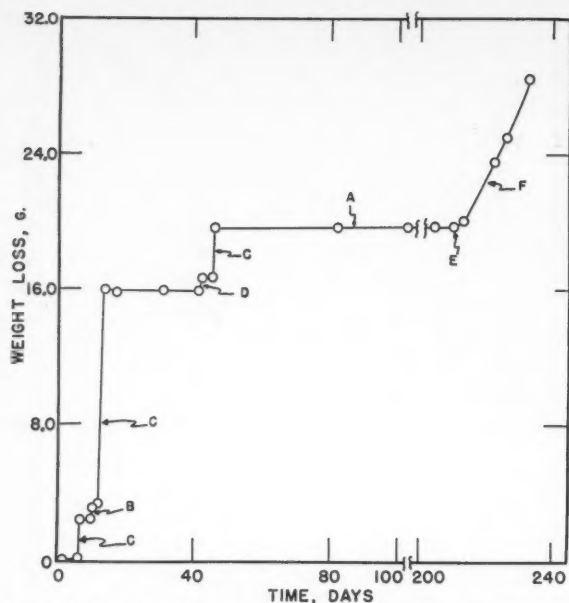
Figure 5—Long term reaction rate curve from coupons exposed to well fluids. Several boosts and blows occurred and there was a 165-day period of normal production with no water contact. A—IPY=0.0004; B—boost; C—blow; D—experimental wash, IPY=1.18; E—air line perforated and replaced, total IPY (calculated from zero time)=0.164; F—intermittent water slugs, IPY=0.183.

Figure 6—Section of galvanized air line from well showing perforation (top). Note essentially unaffected area (bottom).

Figure 7—Corrosion of galvanized air line on collar and adjacent tubing which touched interior of sulfur producing tubing.

Figure 8—Localized attack on interior of galvanized air line where contact was made with next concentric tube. Note slight effect elsewhere.
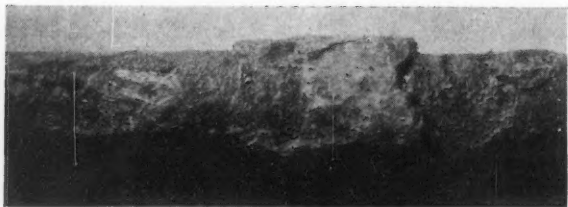
rate. From the last blow to the time the air line perforated the slope of the curve gave an IPY value of 0.0004. Using the total weight loss from zero time to the time of air line perforation, the IPY value
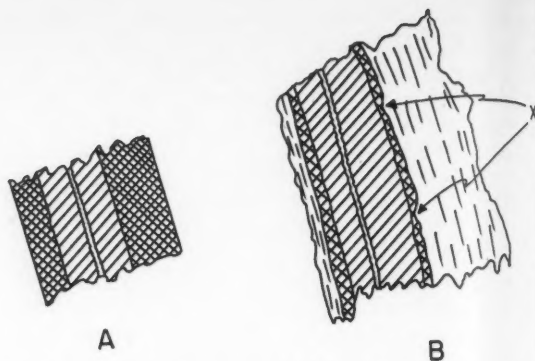
Figure 9—Sketches of galvanized pipe of same shipment; A—from stock; B—after exposure in well. Scale 1 mm.= 10μ. The single hatching indicates the steel pipe wall; the cross hatching, the zinc coat; and the other areas, the non-metallic layers after exposure. To the left is shown the interior wall and to the right, the exterior wall. X indicates points from which all zinc was removed.

was 0.164. The original wall thickness of the air line was 0.187 inches. Considering the fact that the point of air line failure was at higher temperature and that metal loss was probably not uniform, the coupon exposure appeared to give an accurate account of the overall reaction rate.

The air line was removed from the well and portions of it were brought to the laboratory for examination and correlation with the rate curves and coupon examination.

Air Line from Sulfur Well

Inspection of the air line did not reflect the attack rate indicated by the coupons over the entire surface. Instead only a few areas were badly corroded and it was some of these which had perforated. A photograph of a section at one of the penetration points is shown in Figure 6. It can be seen that the side opposite the penetrated area in the pipe section showed only a slight surface attack. Figures 7 and 8 give other views of the corroded areas on the pipe.

The penetration points in this well and inspection of the air line from other wells indicated that the corrosion was more severe when direct contact was made with the internal surface of the next larger tubing. This was particularly true of the collars which tended to corrode where they contacted the next outer concentric tube. Figure 7 shows a collar with adjacent pipe corroded in this manner.

Effect of Galvanizing

The air line was made of 1¼-inch O.D. galvanized heavy duty steel. It was apparent that not all of the galvanizing had been removed during well exposure on that portion of the pipe surface which showed little attack. Cross sections of segments of the air line were prepared by imbedding them in plastic and then polishing by the usual metallurgical procedures. Sketches of cross sections of pipe before and after exposure to well conditions as seen with a microscope are shown in Figure 9. On the areas where no apparent penetration had taken place there was a layer of corrosion products overlaying a thin layer of the

original zinc coating. From the decrease in thickness of the original galvanizing and the appearance of the exposed surface, it was apparent that the scale was the product of the reaction between the corrosive medium and the galvanizing.

Microanalysis of the scale showed it to contain Al and Mg in significant quantities along with ZnS. Spectrographic analysis showed that the original galvanized coat contained unexpectedly large amounts of both Al and Mg. It was clear that the galvanizing was affording definite protection and that the Al and Mg might have had some beneficial effect.

Laboratory Investigations

Potential Measurements

Because it was not evident why the zinc did not react with the medium rapidly and leave the iron unprotected, potential measurements were made on portions of the same air line. The whole surface of the half section of pipe except the outside face was covered with stop-off lacquer as shown in the sketchs in Figure 10. The potential of such samples in saturated KCl solution and in 1% NaCl solution was measured against a saturated calomel electrode using a high resistance voltmeter. Since a finite current flowed, the voltage changed some because of polarization. The results given in Table I are of values which were obtained a short time after the circuit was closed and which remained constant for about five minutes. In all cases the metal was the anode of the cell.

TABLE I—Cell Voltage

	EMF in Sat. KCl	EMF in 1% NaCl
Mild steel,		
unexposed to well fluids	0.58	0.50
Pipe before exposure to well	1.02	0.89
Pipe after exposure to well	0.22	0.20

The markedly lower values for the pipe after exposure in the well may be explained in at least two possible ways: by the formation of an insulating layer which increased the circuit resistance but still permitted corrosion to take place or by a reversal of potential of zinc versus steel, resulting in acceleration of attack when the galvanizing was penetrated.

Laboratory Coupon Exposure Method

The field coupon data showed that the most corrosive periods were those when water contacted the steel which had previously been contacted with sulfur. A laboratory evaluation method was devised to simulate these conditions. Standard coupons were suspended for an hour in a molten sulfur bath through which air was bubbled. The coupons, covered by a film of sulfur, were then removed and placed in a bomb made of a heavy duty pipe plug (either 1¼-inch or 2-inch O.D.) and cap. The inside of the plug was fitted with a glass liner so that the contacting liquid was not contaminated by pipe metal. The coupon under study was placed in the liquid contained in the glass liner, the bomb was sealed, and the assembly was then heated in an oil bath to temperature, usually 120° C or 130° C.
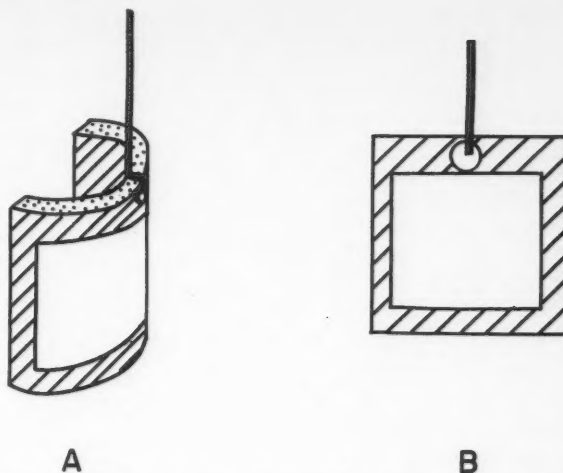

Figure 10—Sketch of pipe section used for potential measurements; A–side view; B–front view. The single hatching indicates where stop-off lacquer covered surface (including the whole back); the clear area was the surface used for potential measurement.

The influence of the time of exposure in the bomb was studied by exposing coupons for various periods. Because of heat transfer lag between the oil bath and the reactor, the temperature did not become constant for some time. Therefore, both weight loss and temperature of liquid in the bomb were determined as a function of time. Typical results are shown in Figure 11. It may be seen that for the bath operated at 130° C, the liquid in the bomb reached maximum temperature only after 20 minutes. The maximum weight loss was reached in about an hour and stayed nearly constant thereafter. The standard bomb exposure time was then arbitrarly set at two hours.

Results of Laboratory Coupon Exposures

Laboratory information on the effect of simultaneous contact of S, H_2O, and air on the corrosion rate of steel has been reported in detail elsewhere.[3]

A number of zinc alloys containing Mg, Al, and mixtures of Mg and Al respectively were prepared. It was found that even small additions of Mg to the zinc made galvanizing difficult and as the amount increased over 1%, it was impossible to make a suitable coating. In order to evaluate higher Mg-Zn alloys alone several strips of such materials were cast. Table II shows the penetration values obtained for mild steel, galvanized steel, and several of the alloys described above in tap water and in 1% NaCl.

TABLE II
Corrosion Rates of Galvanized and Alloy Galvanized Coatings, 130° C

	IPY in Tap H_2O	IPY in 1% NaCl
Mild Steel	0.772	0.968
Galvanizing (Zn)	0.069	0.157
Zn—2% Al	0.046	0.402
Zn—10% Al	0.37	0.972
Zn—2% Al—2% Mg*	0.006	0.026
Zn—2% Al—5% Mg*	0.000	—
Zn—0.014% Mg	0.062	0.122
Zn—0.15% Mg	0.061	—
Zn—0.69% Mg	0.022	0.089
Zn—1.27% Mg*	0.096	0.195

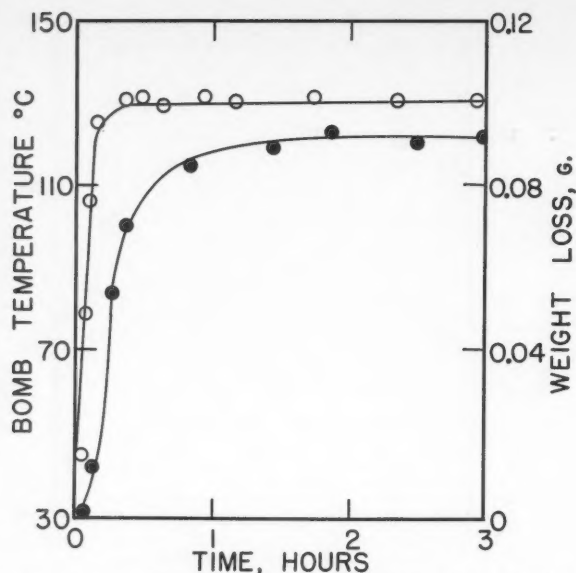* Cast alloys alone, not as a coating.

Figure 11—reaction rate curve from steel coupons exposed to sulfur, water, and air in laboratory apparatus. ●—weight loss curve and O—temperature curve.

These values leave little doubt that galvanizing decreases the rate of attack at least as obtained by this method. It also indicates that the alloy coatings show greater resistance. The choice of alloy seems to make some difference especially in resistance to NaCl attack. The addition of Mg particularly seems to be of value for NaCl solutions.

Field Evaluation of Galvanized and Alloy Galvanized Coupons

A series of galvanized coupons and steel coupons were inserted in a coupon container in the line from a well which was operating erratically. An exposure of nineteen days was obtained during which time the well blew and was boosted eight times. In this exposure five sets of coupons were removed at four day intervals, the last set being removed at time of shutdown. Taking the average slope of the weight loss curves of the descaled samples, the IPY values were calculated with the results shown in Table III.

TABLE III
Field Evaluation of Galvanized Coupons

	IPY
Mild Steel	0.119
Zn	0.0164
Zn—.1% Mg	0.0096
Zn—1.0% Al—0.1% Cu—0.03% Mg	0.0054

Examination of the coupons showed that the

major attack took place on the edges on which the flowing liquid stream strikes. The IPY values for the coated samples are due largely to the losses along the edges and are therefore not uniform penetration values. The galvanized coupons appeared to be subject to considerably greater edge attack than the alloy galvanized coupons.

Discussion

The results of these investigations demonstrate that the most corrosive periods of sulfur production are those during the water contact times *after* exposure to liquid sulfur flow. Zinc resists the corrosive attack better than steel, however it is not sufficiently resistant to stop penetration. Galvanized pipe arrests the corrosion until the galvanizing is penetrated but apparently does not provide cathodic protection. More likely, because of the formation of a protective scale from the reaction of the coating and the corrodents, the usual zinc to iron potential is not established and the iron is then not protected fully by sacrifice of zinc.

The presence of small amounts of Mg and Al in the galvanizing increased the corrosion resistance, particularly in NaCl solutions. Considerable difficulty was encountered in preparing satisfactorily coated specimens of zinc alloys containing Mg and it is evident that this difficulty would have to be overcome for practical application.

If the trends shown by this research are correct, zinc coatings should be useful in protecting against sulfide corrosion in general. Considerably more research is indicated in order to obtain the proper corrosion resistence and ease of fabrication.

The method of testing sulfur corrosion by exposing a sulfur-coated coupon to water on a solution in a bomb gave results comparable to behavior experienced in the field. Thus there is provided for future study a simple means of evaluating variables effecting the corrosion rate. Variation in time, temperature, medium, and metal can be studied by this system.

Acknowledgement

References

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2. R. Fanelli, *Ind. Eng. Chem.*, **38**, 39 (1946).
3. D. A. Shock and Norman Hackerman, *Ind. Eng. Chem.*, (in press).
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Interference From Forced Drainage*

*By ROBERT POPE**

Abstract

A method is described for determining the interference which theoretically may be expected on a long structure due to forced drainage on a similar parallel structure. The method is applied to four-inch welded bare steel pipes and variations are introduced to illustrate the effects of:

a) the presence of coatings on the pipes and

b) changes in soil resistivity, longitudinal conductivity of the structures, diameter of the structures, distance to the anode and separation of the structures.

Important conclusions drawn from this study are:

1. There is no location of the anode at which interference effects are completely nullified. Practical minimum interference is obtained over a wide range of anode location points.

2. For an anode location within practicable distance from the structure the interference effects can theoretically best be overcome by a bond each side of the drainage point rather than one bond at the drainage point.

3. Protective coatings, even those with conductance as high as one mho per kilometer, have very marked effect in reduction of interference current.

4. Variations in dimensions of structures, separations, soil resistivity, etc., have relatively little effect on interference.

FORCED DRAINAGE applied to an underground structure creates earth currents, part of which may be diverted to nearby underground metallic structures and the current thus picked up may cause corrosion of the adjacent structures where it leaves to reenter the earth. Such interception of drainage current has been called "interference" and the current on the adjacent structures "interference current." Because of its accepted usage, this terminology will be used in this discussion.

The magnitude of the interference current may be kept to a practical minimum by discreet selection of the anode location. The corrosive effect of any remaining current on the interfered structures usually may be mitigated by draining it off with properly located bonds of suitable resistance between the structures. This discussion covers the effects which may theoretically be expected between two parallel structures and the relative importance of various factors involved.

Equations for computing the interference current[1,2] were adapted for this purpose and these are applied to two parallel 4-inch welded steel pipes, one of which is drained. Pipes are used in preference to cables because they lend themselves more readily to computation of earth leakage resistance but the results are in general applicable to cables as well as pipes. Also, for purposes of simplification the two pipes are assumed to be similar to each other in their characteristics. This assumption avoids mathematical complications and has little effect on the general conclusions. The equations are applied to illustrate the following effects:

a) the presence of a leaky coating on the pipes,
b) variation in soil resistivity,
c) change in longitudinal conductivity of the structures,
d) change in diameter of the structures,
e) change in distance to the anode and
f) change in separation of the structures.

The effects of these changes are computed for the adjacent pipe in terms of

a) maximum interference current,
b) maximum rate of current loss and
c) length of the corrosion exposure.

To illustrate these effects seven conditions are assumed, as follows:

Case 1: **Basic condition** of 4-inch bare welded steel pipes buried at a depth of one meter in soil of 100-meter-ohm resistivity, with the pipes 10 meters apart and the anode at a distance of 100 meters from the drained structure. The longitudinal resistance of each pipe is .0575 ohm per kilometer.

Case 2: **Uniformly Leaky Coatings** on both structures with a leakage resistance of 1000 ohm-meters. Otherwise conditions are the same as in Case 1. Leaky coatings are assumed because coatings of high insulation would practically eliminate any interaction between the structures.

Case 3A: **Soil Resistivity** of 200 meter-ohms, all other conditions the same as in Case 1.

Case 3B: **Longitudinal Resistance** of structures .02875 ohm/km, half that in Case 1. Other conditions the same as Case 1.

Case 4: **Diameter of Pipes** is twice that in Case 1, but longitudinal resistance and other conditions are the same as Case 1.

Case 5: **Distance to the Anode** is 200 meters, instead of 100 meters as in Case 1.

Case 6: **Separation of Structures** is 20 meters, instead of 10 meters as in Case 1.

Method of Analysis

Because there are no metallic connections to the interfered structure its current must be picked up from and returned to the earth. This current must therefore result from alteration of the earth potential along the structure. In analyzing the situation, consideration must be given to two sources of such

earth potential: The drained structure and its anode. In this discussion they will be considered separately as the "Structure Effect" and the "Anode Effect." The "Net Effect" will be obtained by combining these. In order to investigate the structure effect it will be assumed that the anode is extremely remote so that its effect on either structure is negligible. To investigate the anode effect it will be assumed that current is transferred from such a remote earth electrode to another electrode at the assumed anode location. Because in the cases under consideration the separation of the structures is small compared with the distance to the anode, there will be essentially no difference in the anode effect on each of the two structures.

Attenuation Constant And Other Structure Characteristics

The anode effect as well as the structure effect depends on the attenuation constants of the structures.[3] This in turn depends upon the longitudinal resistance and leakage resistance of the structure as indicated by the following equation:

$$\alpha = \sqrt{\frac{R}{R_L}} \qquad (1$$

where α is the attenuation constant per meter, R is the longitudinal resistance of the structure per meter and R_L is the leakage resistance of the structure for a meter length. The latter includes the resistance of the soil path and the resistance of any coating. Thus

$$R_L = R_C + R_E \qquad (2$$

in which R_C is the resistance of the coating and R_E the resistance of the earth path. R_E can be computed from the equation

$$R_E = \frac{\rho}{\pi} \log \frac{1.12}{\alpha a_1} \qquad (3$$

where $\log = \log_E, = 2.303 \log_{10}$, ρ is the soil resistivity in meter-ohms and a_1 is the equivalent electrical radius of the structure, in meters. For a single structure

$$a_1 = \sqrt{2ad} \qquad (4$$

in which a is the outside radius of the structure in meters and d is the depth of the center of the structure below the surface, in meters. For two close similar parallel structures the equivalent electrical radius a_2 is obtained from the equation

$$a_2 = \sqrt{a_1 y_1} \qquad (5$$

in which y_1 is the separation of the structures, in meters.

By combining the above equations, the following equation is developed, by means of which α the attenuation constant can be computed. For one structure (α_1),

$$\alpha_1^2 \left(R_C + \frac{\rho}{\pi} \log \frac{1.12}{\alpha_1 a_1} \right) = R \qquad (6$$

For two structures (α_2)

$$\alpha_2^2 \left(\frac{R_C}{2} + \frac{\rho}{\pi} \log \frac{1.12}{\alpha_2 a_2} \right) = \frac{R}{2} \qquad (7$$

The values of α per meter and other characteristics are summarized for the seven cases in Table I.

For uncoated pipes, $R_C = O$ and the above equations become for one structure

$$\frac{\rho}{\pi} \left(\log \frac{1.12}{\alpha_1 a_1} \right) \alpha_1^2 = R \qquad (8$$

and for two structures

$$\frac{\rho}{\pi} \left(\log \frac{1.12}{\alpha_2 a_2} \right) \alpha_2^2 = \frac{R}{2} \qquad (9$$

From these equations it can be shown that on bare structures an increase in soil resistivity has the same effect on the value of α_1 and α_2 as a proportional decrease in longitudinal resistance of the structures, thus making the attenuation constants for Cases 3A and 3B identical.

Anode Effect

The conditions considered in the anode effect are inindicated in Figure 1. When the separation of the structures (y_1) is small compared with the distance to the anode (y) as in the assumed case under discussion, the currents in each of the two similar structures at any point, x, are essentially equal. Since the anode affects both structures the characteristics of the structures jointly must be used in the computations. For the current in either structure due to an anode current I(A) the following equation* for a uniformly conducting earth applies

$$I(AN)_x = I(AM)_x = \frac{I(A)}{8} \cdot \frac{2e^{-\alpha_2 X} \log \frac{1.12}{\alpha_2 y} - f(\alpha_2 x)}{\frac{\pi R_C}{2\rho} + \log \frac{1.12}{\alpha_2 a_1}} \qquad (10$$

in which $I(AN)_x$ is the current in the interfered structure due to anode effect, at a distance x from the drainage point, $I(AM)_x$ is similar current in the

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* This is a particular case of equation (6.16) in reference 2, obtained by using in place of ψ ($\propto x$, $\propto y$) an approximation of the latter function applying to small values of $\propto y$.

TABLE I—Characteristics of Pipes Discussed in Text

CASE and DESCRIPTION	1 Bare	2 Coated	3A Double Soil Resist.	3B Half Longit. Resist.	4 Double Radius	Double Anode Distance	6 Double Separation
Depth of Pipe, meter (d)	1	1	1	1	1	1	1
Separation of Pipes, meters, (y₁)	10	10	10	10	10	10	20
Radius of Pipe, meter (a)	.057	.057	.057	.057	.114	.057	.057
Equiv. Elect. Radius 1 Pipe, meter (a₁)	.338	.338	.338	.338	.477	.338	.338
Equiv. Elect. Radius 2 Pipes, meters (a₂)	1.838	1.838	1.838	1.838	2.185	1.838	2.60
Long. Res. microhm per meter (R)	57.5	57.5	57.5	28.75	57.5	57.5	57.5
Leakage Res. of Coating, ohm-meter (R_C)	0	1000	0	0	0	0	0
Soil Resistivity, meter-ohms (ρ)	100	100	200	100	100	100	100
Anode Distance, meters, (y)	100	100	100	100	100	200	100
Attenuation Const. 1 Pipe per kilometer (α₁)	.451	.21	.311	.311	.460	.451	.451
Attenuation Const. 2 Pipes per kilometer (α₂)	.35	.195	.237	.237	.352	.35	.358

drained structure, $I(A)$ is the anode current and y is the distance from the structure to the anode in meters. Values of $f(\alpha_2 x)$ are given in Table II. The equation applies when x is greater than y and $\alpha_2 y$ is less than .1.

For uncoated pipes $(R_C = O)$ the characteristics of the pipes are represented in the value of α_2, a_2 and y which are identical for cases 3A and 3B and similar results are obtained for these cases. In other words the change in anode effect caused by an increase in soil resistivity is the same as the change caused by a proportional decrease in longitudinal resistance of the pipes.

The anode may affect the earth potential at points quite remote from the anode location. Since the effect depends upon earth resistivity, it is evident that remote effects can be predicted only when the assumed value of soil resistivity holds for considerable depth. A surface condition may be misleading if the resistivity below this is materially different. This is illustrated in Figure 2 which shows the earth potential around a point electrode for (a) 1,000 meter-ohm soil, (b) 100 meter-ohm soil, and (c) 1,000 meter-ohm soil with a top layer of 100 meter-ohm soil 10 meters deep.* It will be observed that the potentials in (c) more nearly resemble the conditions for the deeper 1000 meter-ohm soil than they do those for the 100 meter-ohm surface layer.

Thus, when the distance to the anode is large compared to the depth of the upper layer, the anode effect is controlled largely by the deeper resistivity. In most cases the variations in soil resistivity are not so large as in the above example and a reasonable average value can be used for both effects.

Structure Effect

For determining the current in the adjacent structure, a series of curves are derived** giving the interference current at distances from the drainage point in terms of the ratio μ of mutual leakage resistance between the structures to the leakage resistance of each structure. This ratio is given by the following approximate equation

$$\mu = \frac{\log \dfrac{1.12}{\alpha_1 y_1}}{\log \dfrac{1.12}{\alpha_1 a_1} + \dfrac{\pi R_c}{\rho}} \tag{11}$$

Curves for the interference current for various values of μ are shown in Figure 3, as a function of $\alpha_1 x$.

Here for uncoated pipes $(R_C = O)$ the structure characteristics are reflected in the value of $\alpha_1 a_1$ and y_1 so that Cases 3A and 3B are again identical for the structure effect as well as the anode effect.
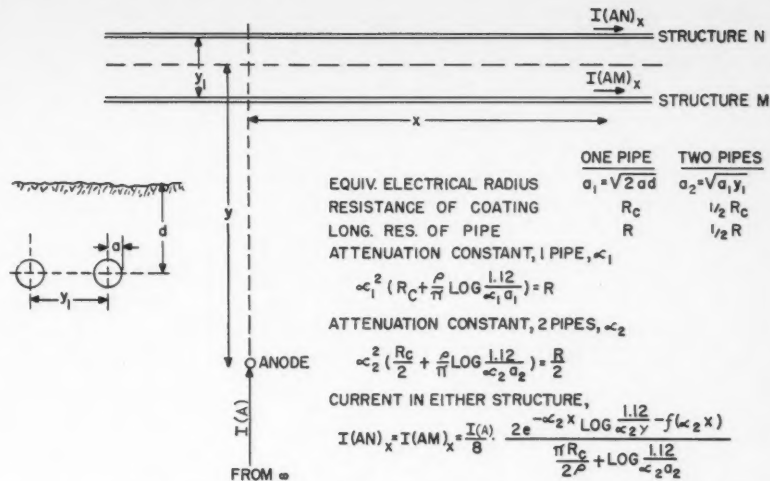
* Reference 2, equation (2.27).
** Reference 2, Page 192.

Figure 1—Forced drainage interference—anode effect. Current in two similar parallel structures caused by a nearby anode.

Discussion of Anode Effect

The anode effect, as obtained from equation (10) was computed for the seven cases mentioned. It is of interest to note Figure 4 which shows the results of computations for Case 1 and compares the current in two structures with the current which would have been found in one structure if the other were absent. The current in the structures at a point opposite the anode is zero and, moving along the structure, a current away from the anode is created in the structures, making them cathodic, up to a point about 1,000 meters away where the maximum current in the structures is attained. Beyond this point the structures lose current and are anodic.

Figure 5 shows the results of calculations for the seven cases. The curves for Cases 4 and 6 came so close together that they were plotted as a single curve. From these curves it can be concluded that for the structures involved, doubling the pipe diameters without changing their longitudinal resistance or doubling the separation of the structures, increases the anode effect current only slightly and doubling the soil resistivity or pipe conductance increases the maximum current about 10%. When the anode is twice as far away the maximum current is reduced about 25%. A leaky coating reduces the maximum anode effect current about 60%. The coat-

TABLE II
Values of $f(\alpha_2 x)$

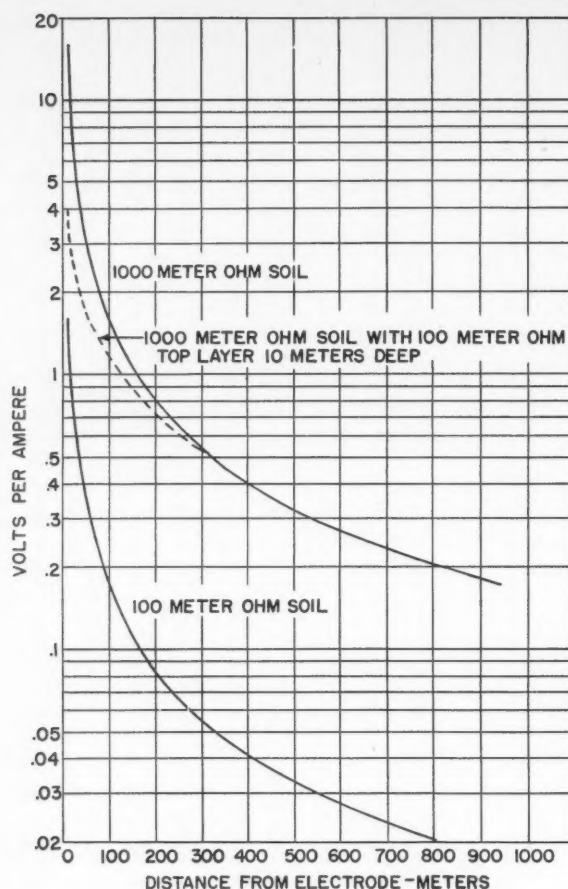| $\alpha_2 x$	$f(\alpha_2 x)$	$\alpha_2 x$	$f(\alpha_2 x)$
.01	8.056	.45	.796
.02	6.670	.50	.647
.03	5.860	.60	.404
.04	5.291	.70	.224
.05	4.846	.80	.087
.06	4.486	.90	−.021
.07	4.182	1.0	−.102
.08	3.918	1.1	−.163
.09	3.688	1.2	−.210
.10	3.483	1.3	−.244
.15	2.704	1.4	−.273
.20	2.166	1.5	−.288
.25	1.763	1.6	−.302
.30	1.448	1.7	−.303
.35	1.190	1.8	−.308
.40	.977	1.9	−.315
		2.0	−.351

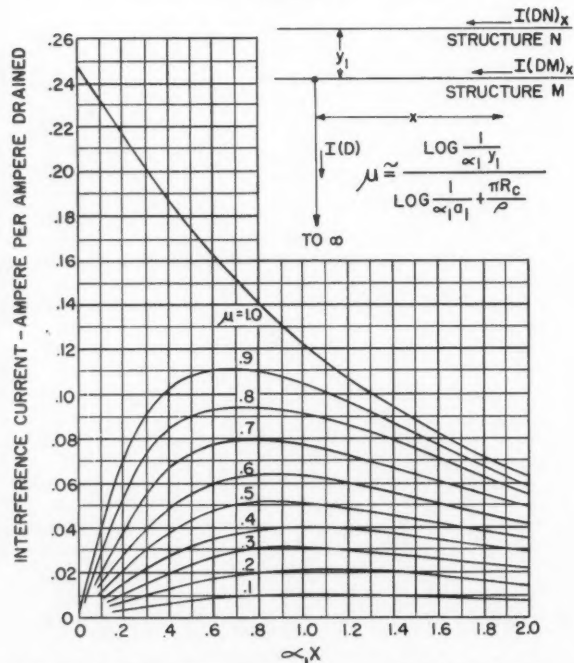Figure 2—Effect of two-layer soil on earth potential around a point electrode.

Figure 3—Forced drainage interference—structure effect. Current in an underground structure caused by drainage on a similar parallel structure.

ing effect would be less pronounced in soil of higher resistivity.

Discussion of Structure Effect

The results of structure effect computations for six cases are shown in Figure 6. Case 5 (anode 200 meters away instead of 100) is the same as Case 1 since these computations all assume a very remote anode location.

The structure effect produces no current in the interfered structure at a point opposite the drainage point on the drained structure. However, other points on the interfered structure have current toward the drainage point (instead of from the drainage point as caused by the anode effect). Thus there is current lost from the adjacent structure in the vicinity of the drainage point. Since the structure effect produces current in the opposite direction from that caused by the anode effect, the values in Figure 6 are plotted as negative. For Case 1, the value of current in the adjacent structure increases for a distance of about 1700 meters and then decreases beyond that, making the structure cathodic at the more remote locations.

For the assumed conditions, doubling the diameter of the pipes increases the maximum structure effect current about 5% and doubling the soil resistivity or the pipe conductance produces a slight increase in maximum current and moves the point of greatest current farther away. Doubling the separation of the structure reduces the maximum current about 10% and a uniform leaky coating reduces the maximum structure effect current about 70%.

Net Effect of Drainage

Figure 7 shows the anode effect current and the structure effect current for bare pipes (Case 1). These effects tend to neutralize each other but the maxima do not come at the same place and therefore they cannot be completely neutralized. Combining these curves graphically produces the net effect curve which shows the net interference current for this case. This curve (Figure 7) shows that, progressing along the adjacent structure from a point opposite the drainage point there is an increasing current away from the drainage point (current pickup) to a maximum of about .025 ampere per ampere drained, at about 350 meters. Progressing farther there is decreasing current (representing current loss) and at about 1150 meters the current is zero. Beyond that point there is an increasing current toward the drainage point (also indicating current loss) until a maximum value of about .015 ampere per ampere drained is reached at about 3350 meters. Thus there is a total loss of about 50 milliamperes per ampere drained over a length of about 3000 meters. However, much of this represents an insignificant current loss rate having no practical effect on the life of the structure. Assuming for purposes of illustration that loss of current at a rate below 10 milliamperes per 1000 meters per ampere drained is insignificant, the length of the exposure created by the interference is about 1600 meters. Of greater importance, however, is the maximum rate of current loss, obtained by measuring
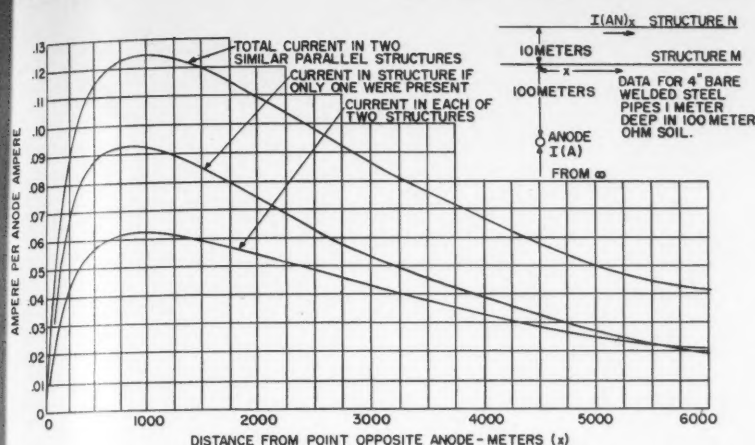
Figure 4—Forced drainage interference —anode effect. Current in two parallel 4-inch pipes caused by a nearby anode.
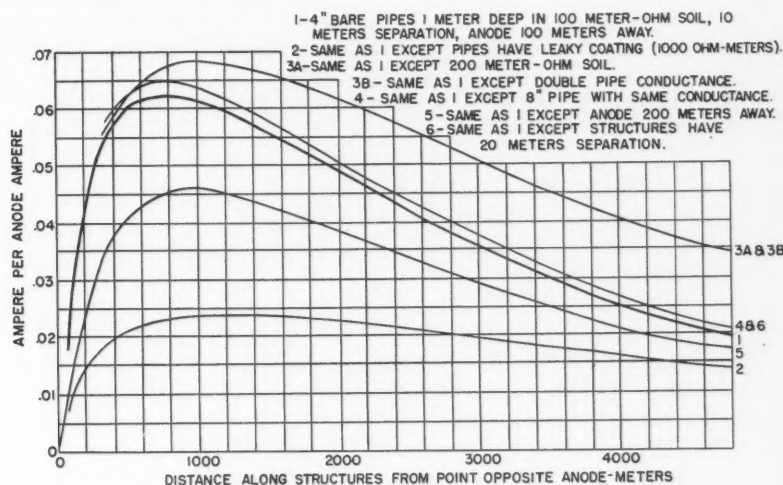
Figure 5—Forced drainage interference —anode effect. Current in each of two parallel pipes—comparison of 7 cases.
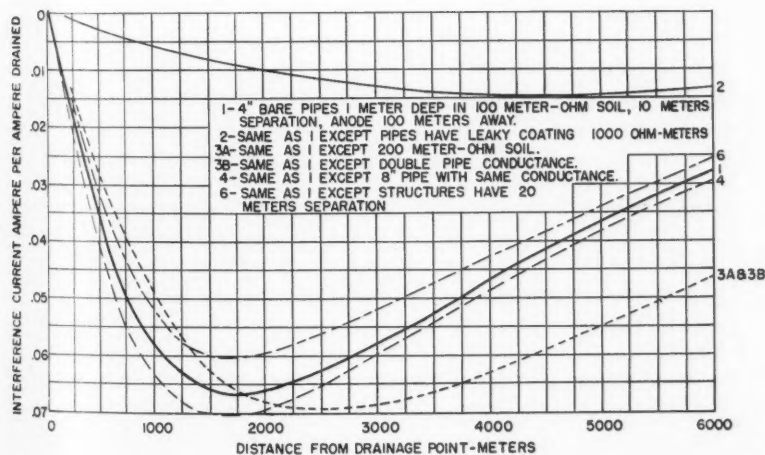
1-4" BARE PIPES 1 METER DEEP IN 100 METER-OHM SOIL, 10 METERS SEPARATION, ANODE 100 METERS AWAY.
2- SAME AS 1 EXCEPT PIPES HAVE LEAKY COATING (1000 OHM-METERS).
3A-SAME AS 1 EXCEPT 200 METER-OHM SOIL.
3B- SAME AS 1 EXCEPT DOUBLE PIPE CONDUCTANCE.
4 - SAME AS 1 EXCEPT 8" PIPE WITH SAME CONDUCTANCE.
5- SAME AS 1 EXCEPT ANODE 200 METERS AWAY.
6- SAME AS 1 EXCEPT STRUCTURES HAVE 20 METERS SEPARATION.

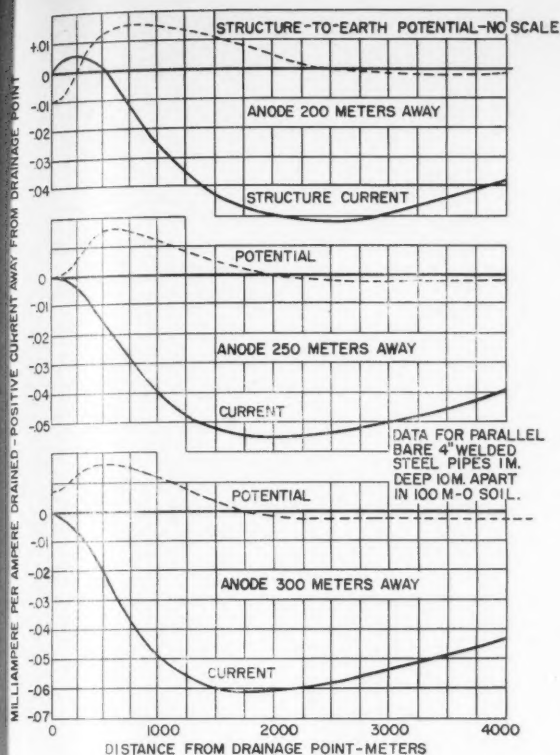Figure 6—Forced drainage interference —structure effect. Comparison of 6 cases.

1-4" BARE PIPES 1 METER DEEP IN 100 METER-OHM SOIL, 10 METERS SEPARATION, ANODE 100 METERS AWAY.
2- SAME AS 1 EXCEPT PIPES HAVE LEAKY COATING 1000 OHM-METERS
3A-SAME AS 1 EXCEPT 200 METER-OHM SOIL.
3B- SAME AS 1 EXCEPT DOUBLE PIPE CONDUCTANCE.
4 - SAME AS 1 EXCEPT 8" PIPE WITH SAME CONDUCTANCE.
6- SAME AS 1 EXCEPT STRUCTURES HAVE 20 METERS SEPARATION

the maximum negative slope of the net effect curve. In this case it is about 34 milliamperes per 1000 meters per ampere drained, obtained at about 500 meters from the drainage point.

Figure 8 shows the net effect curves for the seven cases. These are analyzed to determine a) total current lost per ampere drained b) total length of corrosion exposure c) maximum rate of current lost per

ampere drained and d) length of significant corrosion exposure, and the results are given in Table III. With the exception of the coating, the variations represented in these cases have surprisingly little effect on the corrosion exposure created by the interference currents. It is particularly interesting to note from Figure 8 and Table III that while doubling the distance to the anode materially reduced the maximum

DATA FOR CASE I
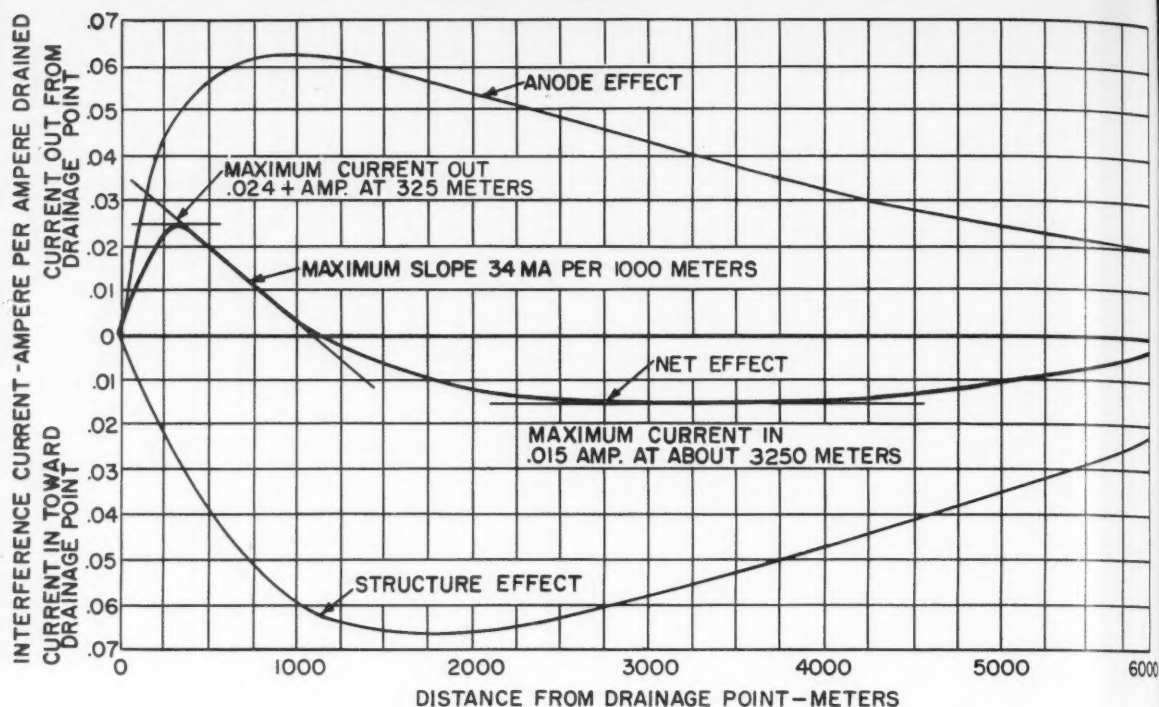
Figure 7—forced drainage interference—combination of anode and structure effects to obtain net effect.

1- 4" BARE PIPES I METER DEEP IN 100 METER-OHM SOIL, 10 METERS SEPARATION, ANODE 100 METERS AWAY.

2- SAME AS I EXCEPT PIPES HAVE LEAKY COATING (1000 OHM- METERS).

3A- SAME AS I EXCEPT 200 METER- OHM SOIL.

3B- SAME AS I EXCEPT DOUBLE PIPE CONDUCTANCE.

4- SAME AS I EXCEPT 8" PIPE WITH SAME CONDUCTANCE.

5- SAME AS I EXCEPT ANODE 200 METERS AWAY.

6- SAME AS I EXCEPT STRUCTURES HAVE 20 METERS SEPARATION.
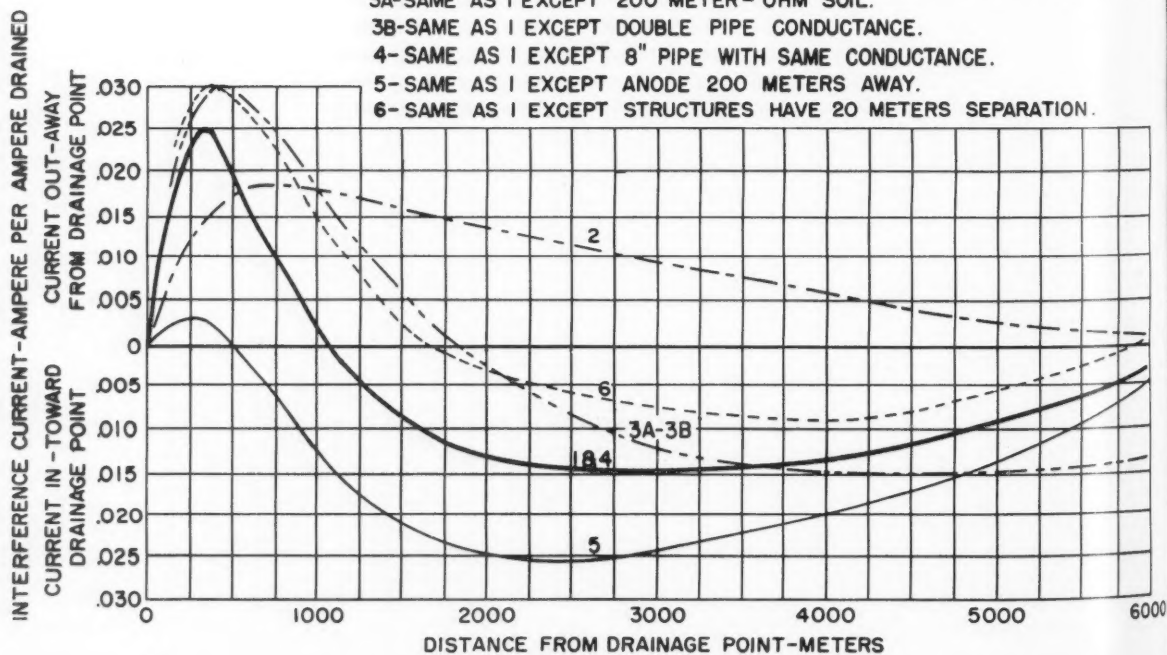
Figure 8—Forced drainage interference—net effect. Comparison of 7 cases.

Figure 9—Forced drainage interference. Effect of various positions of anode on interference current and potential.
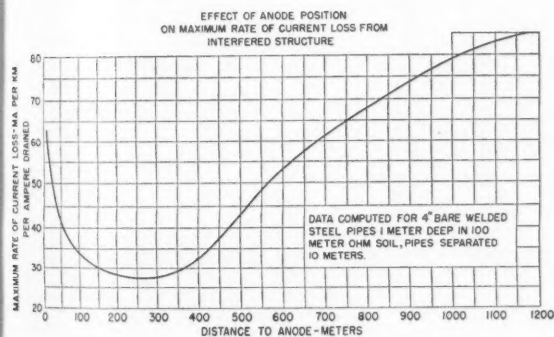
Figure 10—Forced drainage interference.

TABLE III

Corrosion Exposures Created by Drainage Interference

CONDITION	Total Current Loss (1)	Length of Exposure	Max. Rate Current Loss (1) ma per	Length of Significant Exposure
	ma	Meters	Km	Meters
Case 1 Bare Pipes	50	3000	34	1600
Case 2 Coated	20	...	5	None
Case 3 Double ρ or Half R	45	4000	28	1750
Case 4 Double a	39	2400	40	1250
Case 5 Double y	29	2150	30	1100
Case 6 Double y₁	39	3350	34	1325

(1) Per ampere drained.

current away from the drainage point, it also increased the maximum current toward the drainage point and the maximum rate of loss of current was reduced only 25%.

The effect of moving the anode away was investigated further in an effort to locate the point of minimum interference. Such a point has been referred to as the "conjugate location." This led to some difficulty in definition and first effort was made to determine the anode location causing no change in structure-to-earth potential in the interfered structure at a point opposite the drainage point. Figure 9 shows results of computations for Case 1 with the anode 200, 250 and 300 meters away. The structure-to-earth potentials are relative only, since values would depend on variables such as location of the ground potential electrode with respect to the structure, etc. The plotted values are proportional to the rate of current loss or pickup as indicated by the slope of the current curve. With the anode about 250 meters away the current curve at zero point had zero slope indicating no current transfer and therefore zero potential. However, the current curve shows that there is still a rate of current loss equal to 29 milliamperes per kilometer per ampere drained at a point about 700 meters from the drainage point. This rate is almost as large as that computed for the 200 meter anode.

Since the zero potential change did not prove to be a real criterion of corrosion exposure, additional calculations were made for Case 1 for nearer and farther anodes and the maximum rate of current loss was determined. The results are shown in Figure 10 as maximum rate of current loss (in milliamperes per kilometer per ampere drained) plotted against distance to the anode. This shows that under the conditions of Case 1 an anode too remote can be worse than a close anode from the standpoint of maximum current loss. For minimum exposure practically any place from 150 to 375 meters would do.

Figure 9 illustrates another interesting feature. Where interference effects are to be neutralized, resistance bonds are frequently placed between the structures at the drainage point. This is usually good practice where the anode is very remote. Where the anode is less remote, better neutralization of the interference effects might be obtained by the use of two resistance bonds between the structures a short distance each side of the drainage point where the maximum positive structure-to-earth potential is created on the adjacent structure. The closer the anode is to the structures the more desirable the double bond feature appears to be. The most economical arrangement will frequently indicate an anode location resulting in minimum interference but where soil conditions or other considerations complicate the placing of the anode in such a position another location either more remote or closer can be used with proper bonds between the structure.

References

1. E. D. Sunde, "Currents and Potentials Along Leaky Ground Return Conductors." *Elect. Eng.*, **55**, 1338-1345 (1936) Dec.

2. E. D. Sunde, "Earth Conduction Effects in Transmission Systems," D. Van Nostrand Co., New York 1948.

3. R. Pope, "Attenuation of Forced Drainage Effects on Long Uniform Structures," *Corrosion*, **2** 307-319 (1946) Dec.
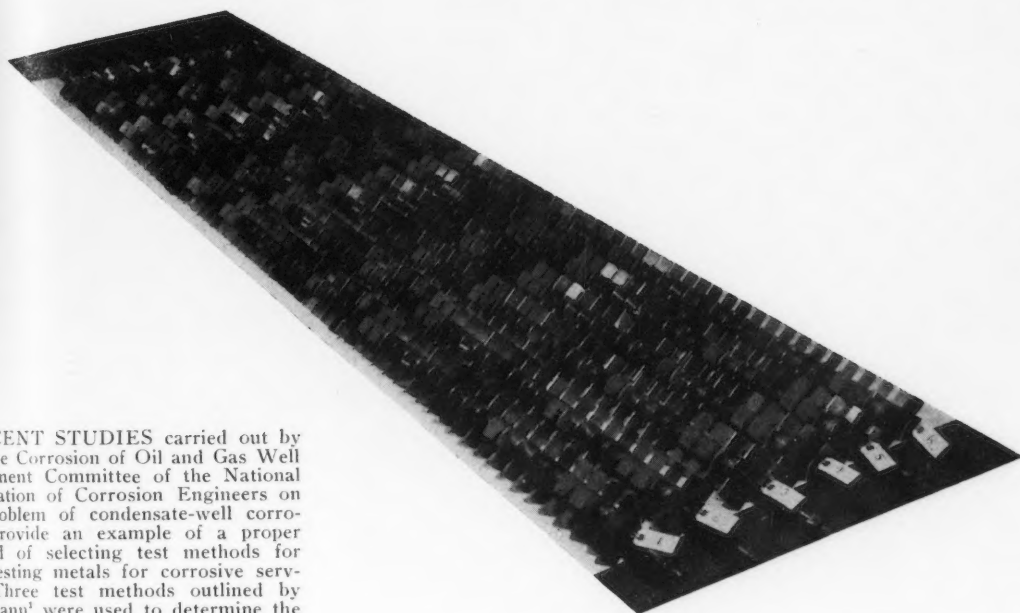
Topic of the Month

Selection of Methods for Field Testing Metals for Corrosive Services

R ECENT STUDIES carried out by the Corrosion of Oil and Gas Well Equipment Committee of the National Association of Corrosion Engineers on the problem of condensate-well corrosion provide an example of a proper method of selecting test methods for field testing metals for corrosive services. Three test methods outlined by Borgmann[1] were used to determine the suitability of 32 metals and alloys for field application in corrosive condensate-wells. Included were the visual inspection of 128 coupons in each of seven wells tested, weight loss determinations on each coupon and pit depth measurements.

Blank weight loss measurements were made of a representative coupon of each metal to determine metal weight lost in cleaning the coupons.

Depths of pits were measured and the depth of the deepest pit was recorded. A qualitative estimate of the extent of pitting was presented by the terms: "Few"—less than one pit per square centimeter; "Numerous"—one to ten pits per square centimeter; "Many"—more than ten pits per square centimeter. An evaluation of pitting occurrence is essential in corrosion testing materials for use as pipe, tubing, tanks, fittings and reaction vessels where one perforation may result in costly and dangerous failures.

The probability of deriving inaccurate data that might result from turbulence effects and varying corrosive conditions was reduced by placing four coupons of each metal tested in repeating order. For example, a carbon steel coupon placed in position 1 would also be tested in position 33, 65, and 97 on the 128-specimen test rod. Positions were reversed on several of the other test spools in other wells to decrease the possibly misleading effect of varying corrosive conditions if these change progressively through the flow container. In addition, the possibility of galvanic attack was reduced also by coating the test rod and installation of insulating spacers between specimens along the rod. This electrical insulation was checked by continuity readings between specimens at the conclusion of the test period.

Corrosion tests such as these are not only useful in determining the corrosion resistance of materials subjected to a specific application, but also are valuable in the development of new alloys for corrosive services. Reproducibility of results in tests conducted in widely separated field areas demands care in the preparation and testing of corrosion coupons.
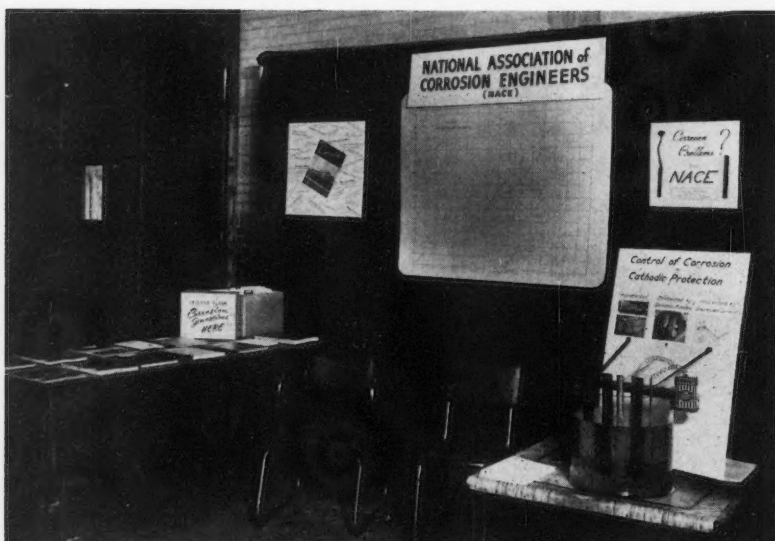
Reference

1. Carl W. Borgmann, "General Discussion of Laboratory Corrosion Testing," p. 953, *Corrosion Handbook*, H. H. Uhlig, Editor, John Wiley and Sons, New York, New York. (1948).

NACE News

New Western New York State Section Formed

This booth at the Houston, Texas, annual Industrial Exposition May 10-14 was prepared by Central Office NACE engineers C. E. Thorney and M. A. Judah. Present at the booth during the 4-day show were members of Houston Section NACE and Central Office staff members.

A new section for North East Region now is being organized in the Western New York area following approval May 10 at the region trustees' meeting in New York City of a petition for the new subdivision of the association. Temporary Chairman is G. L. Cox, The International Nickel Co., Inc., Rochester, New York. Site of the section has not been determined, nor have any other details of organization advanced, sufficiently for comment now, E. R. English, region secretary advised.

Acceptance of the petition was at a region trustees' meeting preceding the joint meeting of the region with Metropolitan New York Section. A symposium on electrolysis problems in the New York area was enjoyed by 128 members and guests at the Building Trades Employers Association, 2 Park Ave., New York.

In addition to the paper by R. E. Pope of Bell Telephone Laboratories, published in this (June) issue of CORROSION, J. C. Howell of Public Service Co. of New Jersey speaking on "Corrosion of Underground Lead Sheath Cables," covered reduction in cost of lead sheaths by using a thinner lead covering under a polyethylene or reinforced Neoprene insulating membrane and advantages from the ues of cathodic protection with galvanic anodes and rectifiers.

A demonstration board was used by C. Thompson, New York Telephone Company consisting of a simulated DC traction system with parallel cable and pipe lines. Effect of electrolysis on these lines was shown, together with ways to overcome or eliminate bad effects.

"Electrolysis Control Measures on the Edison Underground Gas and Electric Systems" was the topic of H. F. Koester and F. E. Kulman of Consolidated Edison Co. of N. Y. Mr. Koester described equipment and procedures in making an electrolysis survey of a complete area. Mr. Kulman described requirements of pipe coatings and cathodic protection systems and advantages to be gained from them.

Problems in the "Installation of the Natural Gas Main in Greater New York," such as underground obstructions, traffic, river crossings, etc., were discussed by M. Bermann of Brooklyn Union Gas Co., New York.

Payton Will Head Chicago Section

Approximately 100 were present at the final meeting of 1949-50 and election of officers held by the Chicago Section April 18. Members and guests participated in an open forum discussion on protective coatings, in which a panel of seventeen active in the protective coating field answered both prepared and extemporaneous questions from the floor.

The Tapecoat Company was host for the social hour of the meeting with Al Bohne, John Bolling, Art Shelves and Jack Clancy sharing the duties.

New officers of the section were elected as follows:

Victor J. Payton, Commonwealth Edison Co., 72 West Adams St., Chicago, Ill., chairman; Franklin M. Watkins, Sinclair Refining Co., 400 East Sibley Blvd., Harvey, Ill., vice-chairman; C. A. Van Natta, Plastic Lining Corp., 914 South Wabash Ave., Chicago, Ill., secretary; Laurie E. Nichols, Public Service Co. of Northern Illinois, 1001 South Taylor Ave., Oak Park, Ill., treasurer.

NACE Booth Gets Favorable Notice

A number of persons actively interested and working with corrosion were made aware for the first time of the activities of NACE during the Houston Industrial Exposition, May 10-14, where the association had a booth, gratuitously provided by managers of the exposition. The booth was arranged by C. E. Thorney and M. A. Judah of Central Office and was manned by members of the Houston Section and Central Office staff.

The booth consisted of a simple demonstration of cathodic protection in which three steel strips suspended in a salt solution were respectively unprotected, protected by current from a battery and protected by a magnesium anode. The unprotected steel rusted badly, while the others were substantially unaffected. Considerable interest in this demonstration was evidenced by visitors and in the display showing a badly corroded condenser tube and bolt. A box was provided for written questions.

Association publications were displayed and copies of CORROSION and other literature were given to interested visitors.

Houston Section members who staffed the booth were P. P. Spafford, Stanolind Oil and Gas Co.; H. E. Waldrin, Gulf Oil Corp.; L. G. Sharpe, Humble Pipe Line Co.; Jack L. Battle, Humble Oil and Refining Co.; Lyle R. Sheppard, Shell Pipe Line Corp., all of Houston. A. B. Campbell, association executive secretary, also helped staff the booth.

South Central Region Meeting October 9-10
To Stress Practical Corrosion Applications

Application and practical aspects of corrosion control measures will be the keynote of the South Central Region's annual meeting October 9-10 at the Rice Hotel, Houston. Tentative plans announced by L. F. Scherer, Texas Pipe Line Co., Houston, general chairman of the meeting, call for joint sessions on production, refining and pipe line problems. Concurrent sessions will be held so the full program may be participated in by pipe line, refinery and production men.

R. B. McLaughlin, president of Texas Pipe Line Co., Houston, will deliver the welcoming address at the luncheon Monday, October 9.

H. H. Anderson, vice president of Shell Pipe Line Corp., Houston, will give the keynote address Tuesday morning.

Programs will be prepared and distributed before the conference.

Present plans do not call for an exhibit in conjunction with the meeting.

TENTATIVE PROGRAM

**South Central Regional Meeting
October 9-10, 1950
Rice Hotel, Houston, Texas**

General Chairman—L. F. Scherer, Texas Pipe Line Co., Houston, Texas.
Program Chairman—Harry Waldrip, Gulf Oil Corp., Houston, Texas.
Co-Chairmen of Arrangements — Alex M. Erganian, Pipe Line Service Corp., Houston, Texas; Charles W. Scammon, Houston Oil Field Material Co., Houston, Texas.

Sunday, October 8

Reserved for committee meetings and registration.

Monday, October 9—Two Sessions

Pipe Line Section—Morning and afternoon. To consist of a series of short papers on pipe line corrosion problems. These will outline conditions, methods of handling and results obtained. The latter portion of the afternoon will be devoted to an open forum of questions and answers.

Production and General Section—Morning and afternoon. To consist of a series of reports on field and laboratory evidence of bimetallic corrosion. The afternoon session will be devoted to short papers on general corrosion followed by an open forum of questions and answers.

Monday Noon

A luncheon and general business meeting will be held at the Rice Hotel. A welcoming address will be given by R. B. McLaughlin, president, Texas Pipe Line Co., Houston, Texas.

Monday Evening

Cocktail hour and banquet.

Tuesday, October 10—Morning

Keynote address by H. H. Anderson, vice president, Shell Pipe Line Corp., Houston, Texas. This will be followed for about 10 minutes by reports on economics of various phases of corrosion, recounting results obtained from actual experience.

Tuesday, October 10—Afternoon

Conducted tours through coating yards in Houston area. Inspections will be made of various types and methods of applying protective coatings. A barbecue dinner at one of the coating yards is scheduled tentatively for the evening.

An invitation has been extended by officials of the South Central Region annual meeting to standing and technical committees of NACE to meet October 8, prior to sessions to be held at Houston October 9-10. Similar meetings were held in 1949 during the regional gathering at Dallas.

Committee chairmen have been asked to notify the general chairman, L. F. Scherer, of probable attendance and time preference so meeting rooms can be secured. The opportunity for committees to advance their work before attending two days of sessions on practical aspects of corrosion control was emphasized.
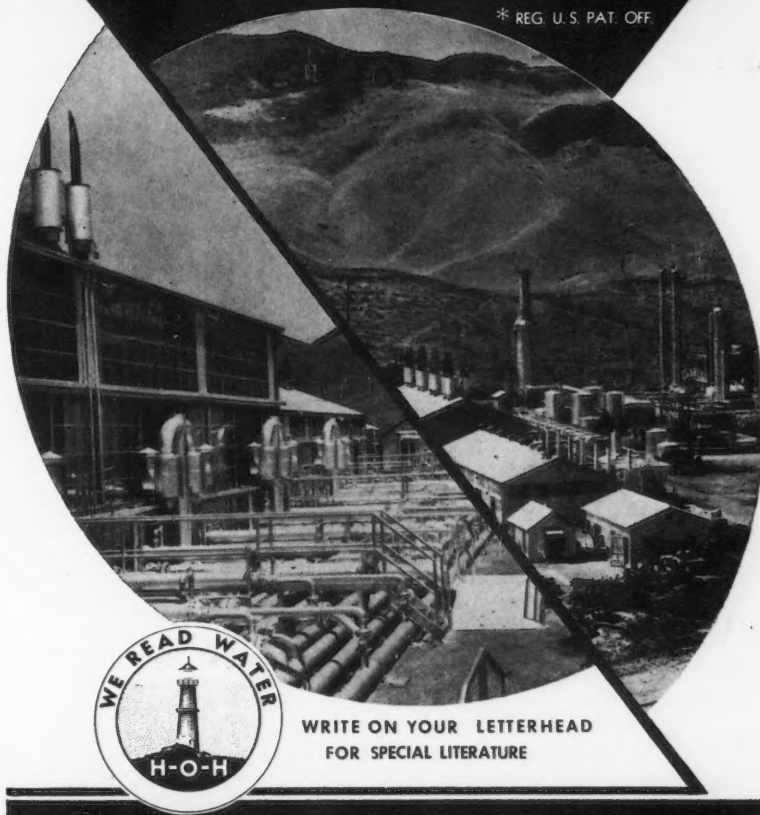
Committee meetings scheduled or tentatively scheduled include:

TP-18—Internal Corrosion in Storage and Transportation of Petroleum. First regular meeting of this group, which was organized during the national meeting at St. Louis in April, will be October 8, according to L. G. Sharpe, chairman.

South Central——

All operating pipe line companies interested in internal sour crude corrosion are invited to work with the committee, and anyone interested in the problem is welcome at the meeting.

TP-3—Anodes for Impressed Currents, Donald H. Bond, chairman, said the committee will meet at the Rice Hotel, October 8. Announcements of time and room will be sent members later.

TP-1—Corrosion of Oil and Gas Well Equipment. Ted S. Zajac, chairman announced that plans for a meeting of this committee are being considered. Announcement of arrangements, if made, will be sent members, he said.

Three Technical Papers, Dinner, Features of South East Meeting

Three technical papers, a business meeting and dinner were featured during the all-day spring meeting of South East Region held April 14 at the Henry Grady Hotel, Atlanta, Ga. Regional Vice-Chairman J. Flynn Johnston called the meeting to order at 10 a.m. Eighteen members registered for the day and evening sessions and twelve or more guests attended some or all of the lectures and discussions.

The technical program included a paper and motion picture on the manufacture and commercial application of plastics (Tenite) to industry by Lewis Connelly, Tennessee Eastman Company, St. Louis, Mo., and a paper and slides on corrosion control in the pulp processing industry by F. L. LaQue, The International Nickel Co., Inc., New York. The afternoon was devoted to an inspection of a metal show and welding clinic underway at the warehouse of J. M. Tull and Company.

The dinner meeting, attended by 23, was featured by an address by R. B. Mears, Carnegie-Illinois Steel Corp., Pittsburgh, Pa., who presented a discussion illustrated by slides on the behavior of numerous metals under a wide variety of conditions.

Herbert W. Dent, American Cast Iron

Three Technical——

Pipe Co., Birmingham, Ala., was named program chairman for the fall meeting of the region by Vice-Chairman Tait. This appointment was made during a business meeting following Dr. Mear's address. It also was decided the next regional meeting should be scheduled in the last two weeks of October or the first two weeks of November at Birmingham.

Notice of the date will be mailed all members.

Tuesday, Wednesday or Thursday were considered best days of the week to hold the meeting, the others being rejected because of travel time considerations.

The group expressed unanimous regret over the extended illness of Regional Chairman J. W. Yeldell and wished him a rapid return to good health.

Corpus Christi Hears Talk on Platforms

"Cathodic Protection of Offshore Drilling Platforms" was the topic of an address by Gordon L. Doremus of Cathodic Protection Service, Houston, at the April 26 dinner meeting of Corpus Christi Section held at the Princess Louise Hotel.

George Mills and Gus Heinemann discussed the proceedings at the national conference in St. Louis. Five from the Corpus Christi Section attended the conference.

Charles Ward and J. C. Mitchell of Magnolia Petroleum Company presented the section with a rostrum.

Next meeting of the section is scheduled June 22.

Anti-Corrosive Masonry Is Topic at Houston Session on May 9

A slide-illustrated lecture on anti-corrosive masonry construction for vessels was the feature of the May 9 meeting of Houston Section, held at Weldon's Cafeteria, Houston. Forty-four attended. The speaker, Robert R. Pierce of Pennsylvania Salt Manufacturing Co., Philadelphia, Pa. developed his address around a schematic drawing showing recommended practice in placing acid-resisting brick lining in a cylindrical tank. Copies of the specification sheet were given those present.

A short business meeting preceding the address involved discussion of meeting nights for fall sessions at which Chairman Oliver Osborn revealed a section member canvass indicated most favored continuing meetings on the second Tuesday of the month. Arrangements were made for a boat trip on the Houston Ship Channel to take the place of the regular June meeting. A dinner at San Jacinto Inn for members and their wives also is being planned.

N. E. Berry is Heard By St. Louis Section

"Corrosion Engineering from Laboratory to Field," by N. E. Berry of Servel, Inc., was the subject of the principal address delivered April 20 at a joint meeting of the American Institute of Chemical Engineers, the Engineer's Club, and the Greater St. Louis Section NACE. Approximately 19 NACE personnel were present for dinner and 30 for the meeting afterward. There were about 100 present from all three organizations.

Dr. Berry discussed various phases of corrosion engineering as professional activity, traced the activities of theoretical basic research groups and added that bridging the gap between discoveries in the laboratories and application in the field will bring satisfactory solutions to problems there.

Philadelphia Section

"Some Aspects of the Design and Fabrication of Equipment for Corrosion Service," by Frank W. Davis and "Causes of Corrosion Currents," by R. B. Mears are scheduled topics for the June 16 meeting of the Philadelphia Section to be held at the Poor Richard Club, Philadelphia.

Officers Reelected By Zinc Institute

Officers reelected at the April 11 meeting of the American Zinc Institute board of directors at St. Louis were: Edward H. Snyder, president. He is president of the Combined Metals Reduction Company, Salt Lake City, Utah; three vice-presidents: Clarence Glass, Anaconda Sales Co., New York; George Mixter, U. S. Smelting, Refining and Mining Co., Boston, Mass.; Raymond F. Orr, Athletic Mining and Smelting Co., Fort Smith, Ark. Erle V. Daveler, American Zinc, Lead and Smelting Co., New York City was reelected treasurer and Ernest V. Ghent continues as executive vice-president and secretary.

NBS Publications on Solids Data Listed

New publications announced by National Bureau of Standards as available from Superintendent of Documents, U. S. Government Printing Office, Washington 25, D. C. are as follows:

"Thermal Expansion of Solids," Circular C468, 29 pp, per copy 20 cents. Contents: 10 methods for determining thermal expansion and procedures used to obtain expansion equations and coefficients. Three types of thermostats are discussed.

"Density of Solids and Liquids," Circular C487, 29 pp, per copy 20 cents. Contents: 11 methods of determining densities of solids and liquids, with illustrations.

Aircraft Corrosion Is Discussed at San Francisco

Because of weight limitations, and the necessity for sustained strength, aircraft are designed and built with corrosion-control measures as a pri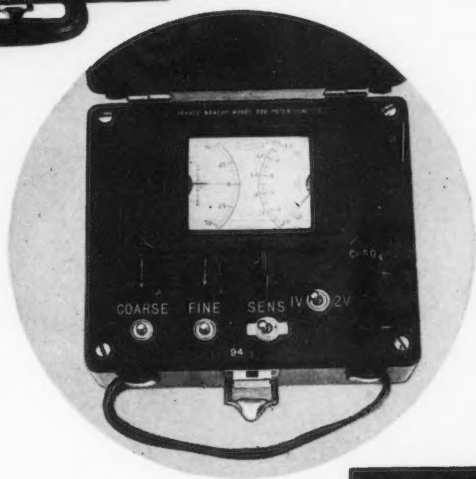ncipal consideration, San Francisco Bay Area Section was told at its April meeting. C. D. Wible, chemical engineer of the Maintenance Division of United Airlines, presented a paper entitled, "Corrosion Problems in Aircraft Maintenance."

The discussion revolved around light metals—aluminum alloys, magnesium— but included material on corrosion of stainless steel, principally of power plant components, and galvanic corrosion from couples of dissimilar metals in instruments and accessories.

The importance of corrosion control was emphasized by Mr. Wible as he pointed out no weakening of parts is permissible, and that the safety record of scheduled airlines is due in no small measure to frequent and careful inspections for signs of corrosion. When discovered, corrective measures are taken promptly, he said.

Protective Maintenance

Principal causes of aluminum corrosion, Mr. Wible reported, were:

1. Chemical attack by exhaust gases, atmospheric salts, cleaning compounds, hard waters and such diverse agents as coffee and mercury.

2. Intergranular corrosion resulting from faulty heat treatment.

3. Bi-metallic galvanic corrosion.

Measures found effective were listed by the speaker as follows: 24ST aluminum can be protected from chemical attack with zinc chromate primer and aluminized lacquer, whereas 75ST Aluminum is so susceptible to exhaust gas corrosion this protection is inadequate. Corrosion of the latter alloy is prevented by frequent removal of corrosive deposits. Because coatings cannot be used over most exterior parts because of weight and appearance factors, control is obtained by frequent cleaning.

Cleaning compounds must have low corrosivity and be washed thoroughly from all parts, especially from between fayed surfaces.

Inner Frame Corrosion

The inner frame and surfaces of planes are protected by zinc chromate primer and paint. Buffet areas where coffee is served and battery compartments are protected with acid-resistant paints and battery trays are filled with sodium carbonate to neutralize spills.

Magnesium parts get a protective treatment consisting of a special nitric acid dip followed by a hot water sealing treatment which gives satisfactory resistance to water corrosion and is a good base for paint.

Magnesium Corrosion

Corrosion of magnesium is troublesome particularly in carburetors, landing wheels and center section castings of engines. Trapped water containing corrosive salts generally is cause of the trouble. Frequent draining, better design and primer and enamels have overcome this difficulty.

Stainless steel corrosion usually is associated with carbon and bromine attack at high temperatures and is aggravated by the build-up of lead compounds from the fuel which intensifies and localizes heating. Stress-corrosion cracking of stainless steel in high pressure hydraulic lines also has occurred, and intensive research is under way now on the problem.

A lively discussion followed Mr. Wibles' talk.

Another feature of the program was a color motion picture "Pipeline" which covered technical details of the design surveying, trenching, corrosion protection and inspection of the Shell pipeline between Jal, New Mexico, and Wood River, Ill. A set-up showing the pumping stations also was included.

Los Angeles Section Elects Officers; Meetings Set

Panel Discussion is Held at Fort Worth

North Texas Section held a panel discussion program at its April 24 meeting at Fort Worth. James A. Clay, Jr., of Service Engineers, Inc., Fort Worth, acted as chairman. There were 35 present.

Officers for the Los Angeles section, the same as those of Western Region, were named at the April 26 dinner meeting of the group held at Rodger Young Auditorium, Los Angeles. Officers are D. T. Jones, chairman; L. L. Whiteneck, vice-chairman, and M. M. Schilling, secretary-treasurer. Forty members and 2? guests were present.

A round table discussion of anodes for cathodic protection was preceded by five talks by T. H. Gilbert, Southern California Gas Co., L. L. Flor, LaMesa, Lemon Grove and Spring Valley Irrigation District; A. L. Patterson, Southern Counties Gas Co.; C. D. Ford, Electro Rust-Proofing Co., and W. E. Kirkendall of Los Angeles Department of Water and Power.

Proposed by-laws for the section have been mailed to members and will be voted on at next meeting June 21. Future meetings are scheduled by the section also on August 16, October 18 and December 20.

Tentative Date Set for Case Corrosion Course

Tentative date for the beginning of the corrosion short course to be given at Case Institute of Technology, Cleveland, Ohio, is September 25, R. B. Hoxeng of the institute advises. No further information about the course has been given.

Cable Sheath Group Members Are Sought

Members of NACE interested in corrosion of cable sheaths are invited to be active in the recently-organized Technical Practices Committee 16—Electrolysis and Corrosion of Cable Sheaths. Initial work of the committee, it has been announced by Irwin C. Dietze, chairman, will be to outline a program consistent with the objectives of studying, collecting and compiling technical data on electrolysis and corrosion of lead and other cable sheaths. Mr. Dietze emphasized that the committee's scope included cable sheaths of all kinds.

Those who wish to participate in this work are asked to write Mr. Dietze care of Department of Water and Power, City of Los Angeles, Box 3669 Terminal Annex, Los Angeles 54, Cal.

Return of Conference Discussions Solicited

Return of completed remarks forms which were sent to all who submitted written discussion records at the recent conference of the association in St. Louis is urged. The collected discussion records are to be sent to authors soon for author's comments on the remarks and questions asked.

Because conference papers are being published more speedily than last year, it is more important than ever that the remarks be quickly completed so they may be published with the paper to which they refer. In the case of remarks completed after a paper has appeared in CORROSION, they will appear separately in later issues properly notated

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A round table discussion of anodes for cathodic protection was preceded by five talks by T. H. Gilbert, Southern California Gas Co., L. L. Flor, LaMesa, Lemon Grove and Spring Valley Irrigation District; A. L. Patterson, Southern Counties Gas Co.; C. D. Ford, Electro Rust-Proofing Co., and W. E. Kirkendall of Los Angeles Department of Water and Power.

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Summary of Talk on Furfural Corrosion is Given

Following is a summary of the talk given by Frank R. Jelinek of Neches Butane Products Co., Port Neches, Texas, to members of the Sabine-Neches Section NACE at a meeting February 23 at Orange, Texas:

Furfural Corrosion in Extractive Distillation Equipment

Neches Butane Products Company's plant at Port Neches, Texas, a government owned butadiene plant, employs several 100-tray fractionating towers to separate close boiling point C_4 hydrocarbons. In order that the relative volatilities of the hydrocarbons may be altered so that large scale fractionation is practical, furfural is used as a selective solvent to separate butylene-1 from isobutane, butylene-2 from normal butane, and butadiene from butylene-1.

After several months following initial plant operation, it was found that towers, heat exchange equipment, piping, and mechanical equipment were coking up and suffering corrosion (by reduction). Corrosion was found in weld areas and stressed portions of the equipment and coke was being deposited on the trays and in the lines and pumps.

Simulated plant studies were conducted to combat the corrosion and it was found that a furfural-water mixture (94% and 6%), when heated as high as 300° F, produced acids and a furfural polymer, resulting in a loss of furfural of about 5000 lb./day. Also, there was indicated that the rate of acid formation was essentially constant in the absence of hydrocarbons, regardless of acid and polymer concentrations, rate of polymer formation increased with an increase of polymer concentration and/or acid concentration and the rate of acid and polymer formation in the furfural varied in the presence of hydrocarbons. The presence of butadiene particularly contributed to additional polymer formation.

An attempt was made to neutralize the furfural-water streams with soda ash since the pH averaged approximately 4.0. It was found that even with an excess of 200 per cent of soda ash that little neutralization was being effected, probably due to the difficulty of contacting the soda ash with the acid in the furfural-water streams. In addition, it was felt that soda ash may have been a contributing factor in additional polymer formation.

Additional studies, thereafter, suggested the use of primary, secondary and tertiary amines as an inhibitor of the acid in the furfural streams. However, the primary and secondary amines could have been expected to react with the furfural and since the tertiary amines, which have no hydrogen joined to the nitrogen atom would in most cases not be expected to react with the furfural.

Pilot Plant work indicated that triethanolamine, a viscous and very hydroscopic liquid, could be expected to solve the corrosion problem since it is easily soluble in furfural, miscible in water, slightly soluble in hydrocarbons, boils above 600° F at atmospheric pressure, non-toxic, and does not tend to cause foaming in the towers. Also, of great economic value was the fact that polymer formation in furfural was vitally affected by the presence of TEA when the furfural-water streams were maintained at a pH of approximately 7.0.

After a trial run on a plant-wide scale, triethanolamine pumping injecting facilities were installed at an injection rate of approximately 1 GPH, which produces approximately 0.03% TEA in the furfural-water streams.

The use of triethanolamine has practically eliminated corrosion, reduced furfural polymer formation by more than 75 per cent, and reduced loss due to downtime because of corrosion and fouling, resulting in a total savings of approximately $234,000.00/year.

This work was carried out under sponsorship of the Reconstruction Finance Corporation, Office of Rubber Reserve, in connection with the government's synthetic rubber program.

ASM Meeting Set

Seven chapters of the American Society of Metals located in or partly in Pennsylvania will meet June 16 and 17 for their Seventh Biennial Pennsylvania Interchapter Meeting at State College, Pa., under auspices of the Penn State Chapter. Included in the announced technical program will be an address by Dr. Cyril Stanley Smith on "The Microstructure of Metals."

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Numerous Significant Corrosion Items Included in June 28 ASTM Program

Items of probable corrosion-interest scheduled for presentation during the 1950 American Society for Testing Materials meeting beginning June 28 at Atlantic City are as follows:

Reports
A-5 Corrosion of Iron and Steel; A-10 on Iron-Chromium (Nickel) Related Alloys; B-3 on Corrosion of Non-Ferrous Metals and Alloys; B-8 on Electrodeposited Metallic Coatings.

Papers on Metals
Some Considerations in the Joining of Dissimilar Metals for High Temperature Service by O. R. Carpenter.

Spray Testing With Natural and Synthetic Sea Water. II. A Study of Organic Coatings by A. L. Alexander and Thomas P. May.

A Synthetic Sea Water and Its Corrosion Characteristics in Salt Spray Testing by T. P. May and A. L. Alexander.

Magnesium—Cerium Wrought Alloys for Elevated-Temperature Service by K. Grube, J. A. Davis and L. W. Eastwood.

Magnesium—Cerium Cast Alloys for Elevated-Temperature Service by K. Grube and L. W. Eastwood.

Effects of Anodic Coatings on the Fatigue Strength of Aluminum Alloys by G. W. Stickley and F. M. Howell.

Aluminum—6 Percent Magnesium Casting Alloys for Elevated-Temperature Service by L. W. Eastwood, W. Hodge and C. H. Lorig.

The Effect of Various Treatments on the Fatigue Strength of Notched S-816 and Timken 16-25-6 from Room Temperature to 1200 Degrees F by W. E. Jones and G. B. Wilkes, Jr.

Effect of Temperatures on the Mechanical Properties, Characteristics and Processing of Austenitic Stainless Steels by V. N. Krivobok and A. M. Talbot.

Sigma Phase and High Temperature
The Formation of Sigma and Its Influence on the Behavior of Stabilized 18-8 Cr-Ni Steels in Concentrated Nitric Acid by R. S. Stewart and Stephen F. Urban.

Effect of Prolonged Exposure at Elevated Temperatures on the Microstructure and Mechanical Properties of AISI Type 310 Stainless Steel by G. N. Emmanuel.

Corrosion, Erosion of Gas Turbine Materials
Coal Ash Corrosion of Metals at Elevated Temperatures by C. T. Evans.

Oil Ash Corrosion of Metals at Elevated Temperatures by C. T. Evans.

The Stress-Rupture Properties of Inconel and Inconel "X" in SO_2-Containing Atmospheres by E. N. Skinner.

Stress-Corrosion Tests on Turbo-Supercharger Materials in the Products of Combustion of Leaded Gasoline by G. B. Wilkes, Jr.

Hydrogenizing Reactions of Gases on Metals at Elevated Temperatures by C. A. Zapffe and F. K. Landgraf.

Concrete, Lime, Etc.. Materials
C-15 on Manufactured Masonry Units.

Testing Cement-Base Paints and Dampproofers by William Spurgeon.

Results on Testing Surface Waterproofing by F. O. Anderegg.

Miscellaneous
D-1 on Paint, Varnish, Lacquer and Related Products.

D-2 on Petroleum.

D-8 on Bituminous Waterproofing and Roofing Materials.

D-9 on Electrical Insulating Materials.

D-10 on Shipping Containers.

D-11 on Rubber.

D-15 on Engine Antifreezes.

D-18 on Soils for Engineering Purposes.

D-19 on Industrial Water.

D-20 on Plastics.

E-1 on Methods of Testing.

E-3 on Chemical Analysis of Metals.

E-7 on Non-Destructive Testing.

E-9 on Fatigue.

Joint Committee on Effect of Temperature on the Properties of Metals.

Effects of Elevated Temperatures on Strength of Thermosetting Laminates by Nathan Fried and R. R. Winans.

Outdoor Weather Ageing of Plastics Under Various Climatological Conditions by S. E. Yustein and R. R. Winans.

Electrochemical Society Pittsburgh Section to Hold One-Day Meeting

Pittsburgh Section, Electrochemical Society will hold a one-day meeting June 16 at the Alcoma Country Club. The technical program will be in two sessions, one beginning at 10:00 a.m. and the other at 1:30 p.m., with an informal luncheon intervening. Following the afternoon technical session facilities of the club and the club golf course will be open to members and guests.

Guests are welcome. Those who wish to attend may apply to either J. M. Bialosky, Carnegie-Illinois Steel Corp., Research Laboratory, Pittsburgh 13 or Eldredge Camp, Westinghouse Electric Corp., Research Laboratory, East Pittsburgh.

Official Dates Are Set For 1951 Conference

Official dates for the 1951 Conference in New York City of the National Association of Corrosion Engineers have been set as March 13-16 inclusive. March 12, Monday, will be set aside for committee meetings, following the precedent set at St. Louis. All sessions and exhibits will be at the Statler Hotel.

Officers Are Named At Metal Powder Association Meeting

Officers elected by the Metal Powder Association at an April 25 meeting at Detroit were: B. T. duPont, sales manager, Plastic Metals Division, National Radiator Co., reelected president; T. L. Robinson, the Wel-Met Co., reelected vice-president and W. P. Schenck, superintendent of the Scrub Oaks Division of Alan Wood Steel Co., was elected chairman of the board. New directors elected were T. L. Robinson, the Wel-Met Co., and H. W. Fischer, American Electro Metal Corp.

NBS Testing

Testing facilities and services available from the National Bureau of Standards, Washington, D. C., which stem from its custody of measurement standards are outlined in a 93 page circular. NBS Circular C 483, available from Superintendent of Documents, U. S. Government Printing Office, Washington 25, D. C., at 25 cents a copy.

Corrosion News Deadline: 10th of Month PRECEDING Date of Issue

Finish to Resist Water Impingement Erosion On Leading Edges of 700-Mile-an-Hour Airplanes Sought by Navy Department Bureau of Aeronautics

By ALVIN C. GOETZ*

The Navy Department, Bureau of Aeronautics, is seeking the assistance of industry, through the "NSIA Paints and Related Protective Coatings Advisory Committee," in the development of an erosion-resistant finish system for use on leading edges of high speed aircraft. This committee is one of many industrial advisory groups organized and sponsored by the National Security Industrial Association in its comprehensive program to make available to the armed services the benefit of disinterested industrial advice and assistance in the solution of problems.

To provide the Bureau of Aeronautics with this assistance, as the first step in its program, the NSIA Committee is collecting for the bureau all recently developed information regarding new and novel finishing schemes and materials, improvements in known finishing schemes and materials, radical departures from conventional finishing practices, unique developments in resins, plastics, film forming materials and adhesives which may have application in

* Eagle-Picher Co., American Building, Cincinnati, Ohio.

this problem. The society is cooperating in this program by publishing this request.

The bureau and NSIA will appreciate the cooperation of all concerns which are interested in, or producing, or have information concerning such materials, processes or finishing schemes whether or not they are currently of direct or contemplated manufacturing interest to the extent of having them submit all relevant technical information. Samples are not desired at this time, but will probably be requested at a later date.

Replies to this inquiry should be addressed to:

Mr. Alfred Malloy
Materials Branch
Bureau of Aeronautics
Department of the Navy
Washington 25, D. C.

Or:

Mr. Patterson Humphrey
National Security Industrial Association
110 William Street
New York 7, New York.

The Bureau's Objective

The bureau is seeking to develop a suitable primer and topcoat finish system for the leading edges of high speed aircraft for the purpose of resisting erosion due to the impingement of rain and other precipitation at speeds in the neighborhood of 700 miles per hour. Although the logical requirement is for a topcoat for universal use on all the fol-

lowing aircraft structural materials which require painting; i.e. aluminum, magnesium, stainless steel, and fiberglass laminate; nevertheless, separate prime coat materials are permissible, if required, to obtain the best possible adhesion on each substrate. Consistent with other important factors, such as availability, economy, etc., extension of the use of the developed coating to the balance of the aircraft exterior surfaces, including exterior components and accessories, will receive serious consideration, in order to solve other troublesome problems, such as "oil-canning," etc.

The need for this finish system arises as a result of greatly increased operating speeds of military aircraft. Organic coatings heretofore employed on the leading edges of jet-propelled and other high speed military aircraft have been found unsatisfactory because the coatings wear away, usually down to the bare metal, after high speed flights of even very short duration through rain or other precipitation. The force of impact of the impinging particles causes the paint to peel from the forward sections of the wings, horizontal stabilizers, vertical fin, wing tip fuel tanks, and nose of the aircraft. A suitable type of coating, possessing strong adhesion forces at the metal-film interface, is required to resist this force.

The Bureau of Aeronautics is currently concentrating major efforts on the development of a coating of the extensible type for this application, in the

Back in 1942, when we first recommended the addition of acid to a cooling water in order to provide better control over corrosion, the experts gasped—even though the value of low pH values in conjunction with Calgon* had been demonstrated two years earlier in a number of industrial plants, and reports of the experiences of these plants had been published.

It had long been known, of course, that dropping the pH value of the water below 7.0 would tend to change the type of attack on metal surfaces in the water system from one of a localized nature to a general one occurring over the entire surface of the metal. Deliberately lowering the pH value, however, was previously unthinkable, since the total rate of corrosion would not be decreased at the lower values but would usually be accelerated.

Fortunately, these pioneering plants were able to obtain the necessary low pH range of 6.0 to 7.0 by merely decreasing or discontinuing the feed of alkali. Other plants with more alkaline waters have since obtained pH reduction by addition of acid. At these pH values, Threshold Treatment with Calgon quickly solved the problems of tuberculation and pitting.

Results in these plants has demonstrated that: (1) maintenance of pH in the range of 5.0 to 7.0 tends to spread the attack uniformly over the whole surface of the metal, and (2) Threshold Treatment with Calgon is just as effective in controlling the total corrosion over this acid pH range as it is at higher pH values. Combined low pH-Calgon treatment is, therefore, the most effective way of combating corrosion in cooling water systems.

For more detailed information on this and other procedures utilizing Calgon to control corrosion, fill out and mail the coupon below, or write us concerning any specific problem in which you are interested.

Finish to Resist—

firm belief, based on the test results discussed below, that an extensible material is required to resist the cavitation and erosion effects of impacting particles in the sub-sonic and trans-sonic ranges, rather than a hard or porcelain-type coating, as has been advocated in some quarters. In this connection, it is suggested that the coating flows around the impacting particles, dissipates in a very short period of time the energy resulting from the impact, and then rebounds to its original contour. It is, of course, entirely possible that some limiting velocity will be encountered in the supersonic range, beyond which the efficacy of extensible organic coatings would be nullified. In preliminary tests, extensible materials have displayed a many-fold resistance to erosion on whirling arm test devices such as the Cornell Aeronautical Laboratory 500 mph apparatus developed for the Air Material Command, and the 700 mph apparatus developed by the University of Louisville for the Bureau of Aeronatuics. Previously conducted erosion tests employing a blast of carborundum dust with or without accompanying water have been found to measure only the resistance to abrasion caused by these needlelike, impinging grit particles. Since such tests neither simulate rain erosion at high speeds nor evaluate any other factor worthy of consideration in a well-planned erosion test program, they have been discontinued by the Bureau of Aeronautics. In order to assist organizations attempting to formulate high speed aircraft coatings, an approximate desirable goal, which still remains very flexible, is set forth for guidance in

Test Methods for the More Important Requirements:

Tensile strength and elongation at rupture tests should be conducted on free films, employing an hydraulically-operated or electronically-controlled gear-driven tester capable of operation at constant rates of loading, rather than the customary constant rate of travel. Adhesion should be determined with a device such as the Interchemical Adherometer, employing a blade of suitably selected material; an electromagnetically-operated adhesion tester such as that of Dr. Soller of the University of Cincinnati, or with machined test plugs, employing ASTM procedure D897-46T. In choosing an appropriate cement for performing the latter test, it should be noted that Vinylite XYHL has shown outstanding performance in preliminary work with aluminum test plugs, producing adhesion forces in the neighborhood of 7000 psi. Some idea of the order of magnitude of the adhesion of the developed coatings may be gained by manipulation of the coating under a microscope at approximately 30X magnification, employing a wedge-shaped needle. This preliminary examination, using a control material of known adhesion for visual comparison purposes,

will do much to sieve out unsatisfactory materials and thus avoid expensive and unnecessary further testing. (It should be noted that, since the Bureau of Aeronautics' planned program of work with the University of Cincinnati adhesion tester will tax the capacity of this instrument to the limit for the next approximately eighteen months, tests on this particular instrument other than those already assigned regrettably cannot be undertaken.)

The resistance to rain erosion should be determined with an apparatus similar to the Cornell Aeronautical Laboratory's whirling arm test device, in order to simulate service conditions. It is understood that the Cornell Aeronautical Laboratory is willing to conduct commercially a limited number of rain erosion tests, upon direct request.

In rain erosion test work it must be recognized that, in the absence of adequate accompanying adhesion, such tests may result in meaningless data, since the maximum obtainable erosion resistance is not realized if the area under examination is capable of lateral movement at the substrate interface under the force of impact of the eroding particles. Accordingly, every attention must be paid to insure a very high degree of adhesion since **Adhesion Is Considered the Most Important Single Requirement in a High Speed Aircraft Coating, With Extensibility Following Next in Importance.**

The following test should be conducted to determine the water-resistance of the finish scheme insofar as it affects anchorage to the metal:

Anchorage (Tape Test)—Four 3 x 6 inch panels of the appropriate metal shall be carefully solvent cleaned. Two medium spray coats of the primer shall be applied to each panel. The primed panels shall then be coated with the required number of coats of the topcoat material, reduced as prescribed by the manufacturer, followed by air dry or bake as required. The four panels shall then be immersed for 24 hours in distilled water at room temperature. After 24 hours immersion each panel shall be removed from the water, wiped dry with a soft cloth and immediately thereafter, two parallel scratches one inch apart shall be made down to metal, using a stylus, on the portion of panel previously immersed. A one inch wide strip of Federal Specification UU-T-106 masking

TABLE I
Tentative Requirements for High Speed Coatings

Tensile Strength	6000 psi. minimum
Adhesion to 75ST and 24ST clad aluminum alloys	6000 psi. minimum
Adhesion to FS-1h magnesium alloy	6000 psi minimum
Adhesion to fiberglas laminate	Satisfactory
Adhesion to stainless steel	6000 psi. minimum
Elongation of the free film at rupture	100 percent minimum, preferably several hundred percent.
Tensile Product—	
(Tensile Strength x Elong. at Rupture in percent) $\dfrac{\text{Tensile Strength} \times \text{Elong. at Rupture in percent}}{1000}$	600 minimum, preferably 1000
Erosion resistance at 700 mph in a rainfall of 1.0 inch per per hour, average diameter of drops 1.0 mm,	30 minutes minimum
Thickness of coating	.003 inch maximum
Softening temperature	Above 250° F.
Water resistance	Satisfactory
AN-F-42 Type IV Hydrocarbon Test Fluid resistance	Satisfactory
Florida outdoor weather exposure	1 year minimum
During cycle	Not over 300° F. for 20 minutes (cycle of not over 200° F. for 10 minutes would be immediately useful)
AN-F-13 Anti-icing Fluid resistance	Satisfactory
Smoothness	Shall require little or no buffing or rubbing
Color	A-N color No. 623 preferred (exact match not manadatory at this time)

The foregoing is offered purely as the basis for preliminary work in order to establish a definite goal for workers in this field.

Finish to Resist—

tape shall be applied, adhesive side down, across the scratches. The tape shall be pressed down using two passes of a 4½ pound rubber covered roller approximately 3½ inches in diameter by 1¾ inches in width, the surface of which has a Durometer hardness value within the range of 70-80. The tape shall then be removed with one abrupt motion and the panel examined for damage, such as removal of the topcoat from the primer or removal of the entire finish system from the metal.

Titanium Metallurgy

Houston Section members were invited to attend a meeting of American Welding Society Houston Section May 25 at which Schuyler A. Herres, Allegheny Ludlum Steel Corp., Brackenridge, Pa., spoke on "Metallurgy of Titanium."

Corrosion Problems

Questions and answers for this heading should be submitted in duplicate if possible, addressed to "CORROSION PROBLEMS", National Association of Corrosion Engineers, 919 Milam Building, Houston 2, Texas. Questions received at the address above above will be sent to E. A. Tice, The International Nickel Co., Inc., N. Y., who is acting editor of the page. All questions will become property of NACE. Questions and replies may or may not be published under this heading and may be answered either by mail directly to the person asking the information, or published under this heading, or both, at the discretion of the editorial staff. Answers to published questions are solicited. Authors of questions will remain anonymous to readers, while authors of answers may remain anonymous if they request it.

No. 33 (a) Can cathodic protection be used on long distance water lines to prevent internal corrosion?

ANSWER

Cathodic Protection can be used on long distance water lines to prevent internal corrosion. The economical feasibility of so doing depends upon a number of factors. To obtain complete protection of the full length of such a line, it is obviously necessary to have a continuous anode inside of the line, or if installed as discreet anodes, spacing between anodes should be not more than about two pipe diameters. In the case of small diameter lines, where the cost of installing either spaced anodes or a continuous anode per unit length of pipe runs proportionately quite high, cathodic protection is usually not found to be economical except in special instances. For the larger water lines, say 24-inch, 36-inch, or larger, the economics may be very much in favor of installing cathodic protection. Depending on total dissolved solids content of the water, either magnesium strip or rod may be suspended in a suitable manner in the center of the pipe in continuous fashion and grounded to the pipe at intervals and reasonable life expected. If the interior of the line is coated and the total dissolved solids in the water are quite high, sufficient current output may be expected from a 17-lb. anode and sufficient spread of current obtained to allow the installation of such anodes at sufficiently great spacing to make this method the most economical approach.—E. P. DOREMUS, Cathodic Protection Service.

No. 33 (b) Is oxygen the only cause of corrosion in long distance water pipe lines when the pH of the water is between 7.5 and 8.0?

ANSWER

Although oxygen is the most common "cause" of corrosion in long distance water pipelines by reason of the fact that it prevents polarization of the cathodes thereby keeping the anodes active, it is not the only depolarizer which may be present in waters. A quite effective depolarizer is chlorine.—E. P. DOREMUS, Cathodic Protection Service.

No. 34—What proportions of bentonite, gypsum and sodium sulfate should be used as backfill for magnesium anodes? What should be the specifi-

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cations of each ingredient as to chemical analysis and grain coarseness to give the best results?

ANSWER

Many combinations of bentonite, gypsum, and sodium sulfate have been used during the past several years as backfill for magnesium anodes. Of all of the combinations which have been tried, that found to yield the best performance as a result of literally thousands of tests conducted by the Dow Chemical Company to develop the ideal backfill is as follows: 75% gypsum, 20% bentonite, and 5% sodium sulfate.

The high percentage of gypsum serves to give the best "efficiency" for the anode. By this, we mean highest number of ampere hours of useful current obtained. The purpose of the bentonite is to absorb and retain soil moisture so as to get most nearly uniform current output from the anode during all seasons. Higher percentages of bentonite have been used, but due to the tendency of bentonite to shrink as its moisture content decreases, these higher percentages in the backfill have resulted in a tendency for the backfill to pull away from the soil, resulting in poor soil contact and a sharp drop in current output of the anode. The purpose of the sodium sulfate in the backfill is to reduce the resistance of the contact between anode and soil. As high as 25 percent of sodium sulfate has been used in previous mixtures, but it has been found that 5 percent results in a sufficient lowering of resistance to yield desired results in practically all types of soil. There is evidence that the higher percentages of sodium sulfate may increase local cell action on the anode and result in poor efficiencies.

There are no critical chemical specifications for any of the above ingredients except the chloride content. The chloride content of any of the ingredients should not exceed 0.1 percent, otherwise good commercial grades of these materials are quite satisfactory.

If the backfill is to be used to install the anode dry or if it is to be used by making up a slurry into which the anode is installed, particle size is unimportant. However, if the backfill is to be used to make a packaged anode where it is desired to wet the anode and obtain immediate readings of current output, particle size is important and the ingredients should be about 20 mesh.—E. P. DOREMUS, Cathodic Protection Service.

No. 36—Can zinc anodes be effectively used to control corrosion and scale formation on cooling water condenser tubes? If not, is the use of zinc hydrosulphide effective? What minimum concentration is satisfactory, and what is the theory involved?

ANSWER

If the question is intended to inquire into the application of cathodic protection to condenser tubes which are cooled by cascading water, it would be impractical to use sacrificial anodes or any other type of cathodic protection to mitigate corrosion on the surface of such tubes. If, on the other hand, the tubes are immersed in the cooling medium, cathodic protection can be quite effectively applied to the mitigation of corrosion on the water side of tubes. Sacrificial anodes in general are probably the most economical current source for this type of application. The possibility is quite great that in many waters zinc would have a tendency to become polarized and would lose its effectiveness. Magnesium would be the best metal to use for such an application since fortunately it does not have a tendency to become polarized.—E. P. DOREMUS, Cathodic Protection Service.

No. 36 (a) When using carbon or graphite rod anodes for galvanic protection of underground steel structures or pipe lines, is it considered profitable to follow the practice of tamping in coke breeze as backfill? If so please explain why.

ANSWER

When a graphite or carbon anode is installed in a backfill, tamping is considered desirable. If the backfill is not tamped, "bridging" may result which will have the following effects: a) Poor electrical contact between anode and soil. b) Backfill will settle in time leaving an uneven fill around the anode. c) There will be a tendency to discharge current unevenly from the anode, resulting in uneven oxidation on the anode itself.

If the backfill is tamped around the anode, the initial resistance will be lower and the current will be discharged to the soil uniformly from the periphery of the backfill. Care should be used in tamping to avoid breaking of the anode.—J. P. OLIVER, Union Carbide and Carbon Corporation.

NEW AND REINSTATED MEMBERS

(Changes Through April 27, 1950)

ALABAMA

HILL, J. ERNEST, Tennessee Coal, Iron & Railroad Co., Fairfield Tin Mill, Fairfield, Alabama.

CALIFORNIA

BROWN, JOHN R., 3525 West 74th Place, Inglewood, California.

KEYT, ERNEST B., California Research Corp., El Segundo Laboratory, 324 W. El Segundo Blvd., El Segundo, California.

NOLAN, JAMES C., Gilmore & Nolan, Inc., 3308 E. Pico Blvd., Los Angeles 23, California.

SCHUHMACHER, GORDON S., Hagan Corp & Sub. Hall Lab & Calgon Inc., 1807 E. Olympic, Los Angeles, California.

COLORADO

SCULL, WILLIAM L., Colorado Interstate Gas Co., Box 1087, Colorado Springs, Colorado.

CONNECTICUT

WEIR, WILLIAM J., Chase Brass & Copper Co., 236 Grand St., Waterbury 91, Connecticut.

DELAWARE

BRIED, EDWARD A., Hercules Powder Co., Naval Stores Dept., Delaware Trust Bldg., Wilmington, Delaware.

HOWELL, WILLIAM E., Hercules Powder Co., 900 Market St., Wilmington, Delaware.

DISTRICT OF COLUMBIA

VAN ETTEN, FRANK M., Bureau of Ships, Navy Dept., 18th & Constitution, Washington 25, D. C.

INDIANA

BELL, W. REX, JR., Poster Parts Co., Wabash at Brown Ave., Terre Haute, Indiana.

MITCHELL, MALCOM, Reilly Tar & Chemical Corp., 1615 Merchants Bank Bldg., Indianapolis 4, Indiana.

ILLINOIS

BOLLING, JOHN G., The Tapecoat Co., 1522 Lyons St., Evanston, Illinois.

BRAUNING, J. F., National Carbon Division, Union Carbide & Carbon Corp., 230 N. Michigan Ave., Chicago 1, Illinois.

BUETTNER, WALTER J., Plastic Lining Corp., 914 South Wabash Ave., Chicago, Illinois.

GOODMAN, E. E., Reilly Tar & Chemical Corp., Box 370, Granite City, Illinois.

LYON, JOHN A. M., Dept. of Electrical Engineering, Techological Institute, Northwestern Univ., Evanston, Illinois.

MAGUIRE, CHESTER G., SR., Eagle Supply Co., P. O. Box 245, Fairfield, Illinois.

MASSING, ROBERT W., The Pure Transportation Co., 35 E. Wacker Drive, Chicago 1, Illinois.

MERWIN, WALTER J., Institute of Gas Technology, 3300 S. Federal St., Chicago 16, Illinois.

PECHART, MAX A., American Tel. & Tel. Co., 7 East Clinton St., Joliet, Illinois.

REED, CLYDE L., Wilson & Co., Inc., 4100 S. Ashland Ave., Chicago 28, Illinois.

SERBULA, STEVE, JR., 1837 N. Natchez Ave., Chicago 35, Illinois.

SWANBECK, LEONARD W., E. A. Obering Oil Co., Box 517, Mt. Vernon, Illinois.

WEISE, F. F., Shell Oil Co., Wood River Refinery, Wood River, Illinois.

WEISERT, ROBERT H., Sales Engineering Inc., 540 N. Michigan Ave., Chicago, Illinois.

KENTUCKY

BROOKS, JERRELL EUGENE, Ashland Oil & Refining Co., 1409 Winchester Ave., Ashland, Kentucky.

KLEIN, JAMES C., Texas Gas Transmission Corp., 423 W. Third St., Owensboro, Kentucky.

McEWEN, CECIL R., Illinois Central Railroad, Paducah, Kentucky.

LOUISIANA

HALE, ROBERT L., JR., Cit-Con Oil Corp., P. O. Box 1578, Lake Charles, Louisiana.

LAUTNER, ROBERT B., 3553 Hyacinth Ave., Baton Rouge, Louisiana.

MARYLAND

McGOWAN, BENJAMIN I., JR., Inter-Coastal Paint Corp., Dundalk 22, Baltimore, Maryland.

WILLIAMS, SANDERS A., The S. A. Williams Co., 1012-16 W. Lexington St., Baltimore 23, Maryland.

WRIGHT, HOWARD P., Baltimore & Ohio R.R., B & O Bldg., Baltimore & St. Charles, Baltimore 1, Maryland.

MASSACHUSETTS

PIERCE, EDGAR M., The Pierce Consulting Engineering Co., 683 Atlantic Ave., Boston 11, Massachusetts.

MICHIGAN

McWETHY, GILBERT A., The Upjohn Co., 301 Henrietta St., Kalamazoo, Michigan.

MISSISSIPPI

DeKAY, CHARLES R., Mississippi Power & Light Co., c/o Central Div. Engineering Dept., Commerce St., Jackson, Mississippi.

HAYNES, HAROLD J., The California Co., Box 360, Natchez, Mississippi.

PERRETT, WILLIAM R., Waterways Experiment Station, P. O. Box 631, Vicksburg, Mississippi.

MISSOURI

ALLEN, WILLIAM W., JR., Owens-Corning Fiberglas Corp., 2005 Continental Bldg., St. Louis 8, Missouri.

DENNIS, SIDNEY, Dennis Chemical Co., 2701 Papin St., St. Louis, Missouri.

FUNCK, DONALD E., 300 East Armour Blvd., Kansas City, Missouri.

HART, STANLEY W., The Glidden Co., 106 Gratiot St., St. Louis, Missouri.

LEBRECHT, G. FRANK, Annheuser-Busch, Inc., 721 Pestalozzi, St. Louis, Missouri.

SHANAHAN, J. P., Shanahan Construction Co. & Associates, 5512 Natural Bridge, St. Louis, Missouri.

NEW JERSEY

SCHROTH, CHARLES R., H. N. Richards Co., 411 White Horse Pike, Haddon Heights, New Jersey.

NEW YORK

CECCON, J. B., Stauffer Chemical Co., Chauncey, New York.

EARL, ROBERT, JR., Earl Paint Corp., 240 Genesee St., Utica, New York.

HIERS, GEORGE O., National Lead Co., Research Lab., 105 York St., Brooklyn 1, New York.

HORNER, RICHARD H., 44 Gramercy Park, North, New York 10, New York.

MEYER, PHILIP A., Gama Industries, Inc., 70 Pine St., New York, New York.

THORNBERG, JOSEPH E., Hooker Electrochemical Co., P. O. Box 344, Niagara Falls, New York, New York.

VANDER VALK, CHRISTY J., Lead Industries Ass'n., 420 Lexington Ave., New York 17, New York.

WHITAKER, H. E., Ford, Bacon & Davis, Inc., 39 Broadway, New York 6, New York.

OHIO

CRANE, JAMES, Cincinnati Chemical Works, Inc., Box 20, Evanston Station, Cincinnati 7, Ohio.

FELDSTEIN, HENRY H., Sugar & Chemical Machinery, Inc., 7829 Euclid Ave., Cleveland 3, Ohio.

HUDACHEK, RAYMOND J., 340 W. Robb Ave., Lima, Ohio.

LOCKE, GILES, Republic Steel Corp., Youngstown, Ohio.

LOCKEMAN, GEORGE F., The Procter & Gamble Co., Engineering Div., M. A. & R. Bldg., Ivorydale, Cincinnati 17, Ohio.

SHOBE, O. F., The Glidden Co. 11001 Madison Ave., Cleveland, Ohio.

VAUGHAN, LEWIS H., Babcock-Wilcox Res. & Dev. Harrisburg & Sawburg Rds., Alliance, Ohio.

WRIGHT, ARMOUR D., JR., Industrial Roofing & Sheet Metal, Inc., 4815 Lexington, Ave., Cleveland, Ohio.

OKLAHOMA

CAMPBELL, J. G., Deep Rock Oil Corporation, 1005 Atlas Life Bldg., Tulsa, Oklahoma.

MENAUL, PAUL, 1308 South Marion St., Tulsa, Okla.

NICKELL, J. F., Supt. of Pipe Lines, Wilcox Oil Co., Box 1440, Tulsa, Oklahoma.

SAGE, JOHN F., Sinclair Oil & Gas Co., Box 521, Tulsa, Oklahoma.

VAN VALKENBURG, JACK, Cathodic Servicing Co., 1024 North Olie, Oklahoma City, Oklahoma.

PENNSYLVANIA

BRICH, JOHN G., Koppers Co., Inc., Flannery Bldg., Forbes St., Pittsburgh 13, Pennsylvania.

BRUNO, CHARLES A., American Viscose Corp., Marcus Hook, Pennsylvania.

CURRENT, F. LEE, Oil Well Supply Co., Oil City, Pennsylvania.

HAAS, NIELDS B., Beaver Grade Rd., R. D. #1, Box 235 Corapolis, Pennsylvania.

WALTON, CHARLES J., Aluminum Co. of America, Aluminum Research Laboratories, New Kensington, Pennsylvania.

WOODARD, A. S., Pennsylvania Salt Manufacturing Co., 1000 Widener Bldg., Philadelphia 7, Pennsylvania.

TEXAS

CRAIG, JAMES H., 3105 Pickwick Lane, Houston, Texas.

HUDDLESTON, CHARLES E., JR., Socony Paint Products Co., P. O. Box 2848, Beaumont, Texas.

KEETON, T. E., Central Power & Light Co., 120 N. Chaparral, Corpus Christi, Texas.

OXFORD, W. F., JR., Sun Oil Co., P. O. Box 2831, Beaumont, Texas.

PETTY, RALPH G., Sinclair Refining Co., Pipe Line Dept., Box 711, Mexia, Texas.

PORTER, FRED B., Southwestern Laboratories, Box 1379, Fort Worth 1, Texas.

POTTS, JOHN, Chemical Engineering Co., P. O. Box 1076, Dallas 1, Texas.

SCHMIDT, R. W., Ethyl-Dow Chemical Co., Freeport, Texas.

WILEY, LLOYD R., JR., Republic Natural Gas Co., M & W Tower Bldg., Dallas, Texas.

UTAH

McENTIRE, ELDON T., Salt Lake City Corp., Water Dept., 114 City and County Bldg., Salt Lake City, Utah.

VIRGINIA

COOK, GEORGE S., 2869 S. Buchanan St., Arlington, Virginia.

FOREIGN

CANADA

EVANS, DAVID H., The British American Oil Co., Ltd., Royal Bank Bldg., King & Yonge Sts., Toronto, Ontario, Canada.

VENEZUELA

McCAMMON, G. A., Attn Technical Library, Creole Petroleum Corp., Apartado 889, Caracas, Venezuela, S. A.

CHANGES OF ADDRESS

(Old Address Follows New Address in Parenthesis)

CALIFORNIA

BRADY, MERRITT H., Electrolysis Dept., Pacific Gas & Electric Co., 4245 Hollis St., Emeryville, California (4245 Hollis St., Emeryville, California).

McCASLIN, KENNETH M., Amercoat Corp., 4809 Firestone Blvd., South Gate, California (Amercoat Divn. American Pipe & Const. Co., 4809 Firestone Blvd., South Gate, California).

MUNGER, C. G., Amercoat Corp., 4809 Firestone Blvd., South Gate California (Amercoat Div. American Pipe & Constr. Co., 4809 Firestone Blvd., South Gate, California).

RICHARDSON, JOHN I., Amercoat Corp., 4809 Firestone Blvd., South Gate, California (Amercoat Div. American Pipe & Const. Co., 4809 Firestone Blvd., South Gate, California).

WELLS, C. KENYON, Long Beach Water Dept., 403 Municipal Utilities Bldg., 215 W. Broadway, Long Beach 6, California (Long Beach Water Dept., 409 Municipal Utilities Bldg., 215 W. Broadway, Long Beach 2, California).

LOUISIANA

PULLEN, P. T., 2304 Creswell, Shreveport, Louisiana (2624 Lakeshore Dr., Shreveport, Louisiana).

MARYLAND

CALLAHAN, V. L., Mathieson Chemical Corp., Mathieson Bldg., Baltimore 3, Maryland (Southern Acid & Sulphur Co., Inc., Box 991, Little Rock, Arkansas).

MICHIGAN

ALTENBURGER, C. L., 741 Denwood St., Dearborn, Michigan (Great Lakes Steel Corp., 741 Denwood St., Dearborn, Michigan).

FELLER, EUGENE W. F., Maujer Publishing Co., 420 Main St., St. Joseph, Michigan (McGraw-Hill Publishing Co., 330 West 42nd St., New York, New York).

MISSOURI

KRUSZYNSKI, EDWARD A., 5001 Oleatha, Apt. 3, St. Louis 9, Missouri (Carter Carburetor Corp., 2840 N. Spring Ave., St. Louis 7, Missouri).

MEYER, WALTER, Nooter Corp., 1400 S. Second St., St. Louis 4, Missouri (John Nooter Boiler Works Co., 1400 S. Second St., St. Louis 4, Missouri).

MITCHELL, JEFFERSON W., 704 West 46th St., Kansas City, Missouri (The National Co-operative Refinery Ass'n., McPherson, Kansas)

NEBRASKA

OLSON, THEODORE W., Box 486, Beatrice, Nebraska (R. F. D. 4, Genesco, Illinois).

NEW JERSEY

BAGNELL, WILLIAM E., Demarest, New Jersey (Ebasco Services, Inc., 2 Rector St., New York 6, New York).

BENEDICT, RISQUE L., c/o Shedaker, Beverly Rd., Burlington, New Jersey (A. V. Smith & Co., 370 Trevor Lane, Bala-Cynwyd, Pennsylvania).

LACHMUND, D. O., Amercoat Corp., 29 New York Ave., Newark 5, New Jersey (Amercoat Division, American Pipe & Construction Co., 29 New York Ave., Newark, New Jersey).

WEST, C. H., Standard Oil Development Co., Esso Engineering Dept., P. O. Box 121, Linden, New Jersey (Standard Oil Development Co., Esso Engineering Dept., Box 37, Elizabeth B., New Jersey).

NEW MEXICO

RUSSELL, JOHN C., 3272 47th St., Sandia Base, Albuquerque, New Mexico (410 South Princeton, Albuquerque, New Mexico).

NEW YORK

COLLINS, HARRY S., Metallizing Engineering Co., Inc., 3814 30th St., Long Island City, New York (Collins, Harry, Metallizing Engineering Co., Inc., 1500 Walnut St., Philadelphia 2, Pennsylvania).

OHIO

BABIN, JOHN, 1121 E. 260th St., Cleveland 17, Ohio (Chase Brass & Copper Co., P. O. Box 2136, Terminal Annex, Los Angeles 54, California).

OKLAHOMA

BALL, JAMES F., Ball Distributing & Engineering Co., 1444 E. 3rd St., Tulsa, Oklahoma (Ball Distributing & Engineering Co., 1004 East 34th St., Tulsa, Oklahoma).

BELSON, MAURICE W., 3956 Richmond, Shreveport 71, Louisiana (D. E. Stearns, 3956 Richmond, Shreveport 71, Louisiana).

COATS, SANFORD C., Tnemec Co., Inc., 1244 Stator Dr., Oklahoma City, Oklahoma (Tnemec Co., Inc., 3122 Roanoke Rd., Kansas City, Missouri).

EVANS, DWIGHT J., Engineering Test Service, 2112 East 15th St., Tulsa, Oklahoma (Branson Instruments, Inc., 4101 San Jacinto St., Houston 4, Texas).

PENNSYLVANIA

BAKER, HAROLD R., JR., 501 W. Hortter St., Apt. D-5, Philadelphia 19, Pennsylvania (Keystone Pipe Line Co., 501 W. Hortter St., Apt. D-5, Philadelphia 19, Pennsylvania).

LEMAY, JACK E., 4628 E. Willock Rd., Pittsburgh 27, Pennsylvania (National Carbon Co., 1715 Clark Bldg., Pittsburgh 22, Pennsylvania).

PALMER, JAMES G., 16 Vine St., Sharon Pennsylvania (P. O. Box 6024, Houston 6, Texas).

STROMQUIST, RUSSELL C., Koppers Co., Inc., Koppers Bldg., Pittsburgh 19, Pennsylvania (Koppers Co., Inc., 4th Floor Chamber of Commerce Bldg., Pittsburgh 19, Pennsylvania).

TEXAS

DAVIS, BILLY H., 1212 Smallwood Ave., Houston 12, Texas (Texas A. & M., P. O. Box 1963, College Station, Texas).

New NACE Corporate Members

New corporate members added in the interval April 15—May 15, 1950 by the National Association of Corrosion Engineers:

DEEP ROCK OIL CORP.
Atlas Life Building,
Tulsa, Okla.
J. G. Campbell,
Representative

CHASE BRASS & COPPER CO., INC.
236 Grand
Waterbury 91, Conn.
William J. Weir,
Representative

FORD, BACON & DAVIS, INC.
39 Broadway,
New York 6, N. Y.
H. E. Whitaker,
Representative

GAMA INDUSTRIES, INC.,
70 Pine Street,
New York, N. Y.
Philip A. Meyer,
Representative

THE M. W. KELLOGG CO.
225 Broadway
New York 7, N. Y.
W. B. Hoyt,
Representative

THE KENDALL COMPANY
Bauer & Black Division,
Polyken Industrial Tape Dept.,
222 W. Adams,
Chicago 6, Ill.
W. J. Miller,
Representative

MICHIGAN-WISCONSIN PIPE LINE CO.,
Detroit, Mich.,
Anthony H. Cramer,
Representative

MINNESOTA MINING & MANUFACTURING COMPANY
411 Piquette Ave.,
Detroit 2, Mich.
D. W. Mahler,
Representative

REPUBLIC STEEL CORP.,
335 Market St.,
Youngstown, Ohio
Giles R. Locke,
Representative

SALT LAKE PIPE LINE CO.
8th West & Beck St.,
Salt Lake City, Utah
Charles V. Baxter,
Representative

SHANAHAN CONSTRUCTION CO. AND ASSOCIATES
5512 Natural Bridge,
St. Louis, Mo.
J. P. Shanahan,
Representative

STAUFFER CHEMICAL COMPANY
420 Lexington Ave.,
New York 17, N. Y.
J. B. Ceccon,
Representative

Changes of Address—

ELKINS, RANDELL L., Shell Oil Co., Box 1509, Midland, Texas (Shell Oil Co., Inc., P. O. Box 744, Great Bend, Kansas).

JOYCE, EDWIN, American Petroleum Institute, 816 Rio Grande National Bldg., Dallas 2, Texas (American Petroleum Institute, 1205 Continental Bldg., Dallas 1, Texas).

MEEK, J. GORDON, Metal Goods Corp., P. O. Box 7225, Dallas 9, Texas (Metal Goods Corp., 1923-A, Ave. Q, Lubbock, Texas).

NELSON, F. M., Texas Gulf Sulphur Co., 1001 Second Nat'l Bank Bldg., Houston 2, Texas (Texas Gulf Sulphur Co., 1013 Second Nat'l Bank Bldg., Houston 2, Texas).

PFREHM, RAYMOND H., Humble Pipe Line Co., Box 1051, Corpus Christi, Texas (Humble Pipe Line Co., P. O. Drawer 2220, Houston, Texas).

PURVIS, FRANK, 1633 W. Woodlawn, San Antonio, Texas (215 E. Magnolia St., San Antonio 2, Texas).

ROBERTS, JOHN P., Engineering Lab., University of Houston, 3801 St. Bernard St., Houston 4, Texas (111 East 22nd St., Houston 8, Texas).

ROSS, GEORGE T., 4121 Ayres, Corpus Christi, Texas (Houston Natural Gas Corp., Box 1188, Houston 1, Texas).

WHITLEY, B. J., JR., Tennessee Gas Transmission Co., P. O. Box 2511, Houston 1, Texas (7203 Toland, Dallas, Texas).

FOREIGN
CANADA

BAKER, J. HYATT, Canadian Industries Ltd., P. O. Box 10, Montreal, Quebec, Canada (Canadian Industries Ltd., P. O. Box 10, Montreal, Canada).

BARNARD, KENNETH N., 74 Victoria Rd., Dartmouth, Nova Scotia, Canada (Naval Research Estb., 74 Victoria Rd., Dartmouth, Nova Scotia, Canada).

CANAL ZONE

MUNDT, H. W., Engineer, Mat'ls., Panama Canal, Box 52, Diablo Heights, Canal Zone (Panama Canal, Box 52, Diablo Heights, Canal Zone).

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The Managing Editor of CORROSION magazine always is happy to see photographs considered suitable as subjects for the covers of the magazine. Address such photographs together with descriptive captions and release for the use to Central Office.

NEW PRODUCTS—Materials—Service—Literature

Rubber Lined steel, using the Vulcalock process which produces a bond strength of over 500 lb. per sq. in. is produced for all kinds of vessels used to handle and transport corrosives by Metalweld, Inc., 26th and Hunting Park Ave., Philadelphia 29, Pa. The company also offers other industrial maintenance services including Koroseal linings, Amercoat coatings, sand blasting (shop or field) metallizing both as a corrosion-resisting coating and to restore abraded surfaces, oxy-acetylene, electric arc and thermite welding and construction equipment sales, rental and repairs.

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United Chromium, Inc. has moved its New York offices to 100 East 42nd St., Zone 17. Concurrently it announced a new primer containing zinc chromate and based on a new synthetic resin. Called Unichrome Primer AP 10, the company recommends it for application to magnesium, aluminum, Monel, tin, steel, stainless steel, copper and brass. No chemical or electrochemical pretreatment is required, the company says, and it provides a finish for application of a wide variety of top coatings even on hard-to-coat aluminum and magnesium. The material is manufactured exclusively by United Chromium under agreement with Princeton Paint Laboratories, Inc., which developed the primer under the name Aviation Primer AP-10. Application is by dipping or spraying; it air dries dust-free in 5 minutes, may be over-coated by synthetics in one hour, by lacquer in two hours, by a baking synthetic in 20 minutes. The baked primer has exceptional resistance to moisture, the company's technical data sheet shows, as well as to solvents, alcohols, naphthas, ketones, coal tar derivatives and solutions of many metallic salts.

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Anaconda Copper's generally used alloys are listed in the first section of the new Copper and Copper Alloy Specifications Index together with applicable specifications and the second section lists specifications in numerical order with a brief description of materials covered as to grade, type, temper, anneal, etc. The 28-page, thumb-indexed book is the third edition of the index published for the convenience of those using standard specifications of engineering societies and government agencies. Copies are available without charge from American Brass Company, Waterbury 20, Conn. Ask for Publication B-34, Third Edition.

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A Humidity Indicator is available consisting of a card 2 inches by 4 inches on which within printed circles approximately 7/16-inch in diameter there has been deposited a pink material which reacts colorimetrically to moisture it absorbs from the air. The circles have been rated as to humidity percentages on an ascending scale from bottom to top. Relative humidity is red at the color change between pink and blue circles. the Manufacturer, Welford C. Blinn, of the Humidial Co., 864 Edgehill, Colton, Cal., suggests the indicators may be used within packages where they may be seen from the outside. Advantages over silica gel indicators claimed are that they are non-dusting, quickly reversible and cover a wide range (10% to 70%) of humidity. They are stable except at humidities over 90% when the colors run. Special production models can be made to specifications.

•

Automatic Regulation and recording of humidity is possible with a Weston Electrical Instrument Corporation device which automatically regulates the wet-bulb depression for which it is set, regardless of fluctuations in dry-bulb temperature. The instrument may be used for applications involving gas. Descriptive literature from the company's 614 Frelinghuysen Ave., Newark 5, N. J., office is available.

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Hermetic Sealing for protection of A. W. Haydon timers from corrosives, water spray, oil, dust, explosive atmospheres and climatic changes is possible with new enclosures for the company's instruments. All enclosures are evacuated to 100 microns and filled to one atmosphere with dry nitrogen so full switch ratings may be used at high altitudes in airplanes where contact capacity normally is reduced.

•

Cross-weave Reenforcement has been added to Oklahoma Glass Fiber Corp., pipe wrapping fabric to improve its strength in all directions. Porosity and other qualities remain the same. New literature is being prepared on this development by Middle West Coating & Supply, Daniel Bldg., Tulsa, Okla.

•

Recovery of Chromic Acid, with possible by-product recovery of metals and metal salts, is indicated as a potential source of saving in metal treating processes such as anodizing, copper stripping, brass pickling and chromium plating, according to Mutual Chemical Company of America, 270 Madison Ave., New York 16, N. Y. Purification of the solutions with oxidation-resistant cationic exchange resins is explained in the publication "Regeneration of Chromic Acid Solutions by Cation Exchange," copies of which are available on request.

•

Steel, Brass and Aluminum-alloy flared and flareless fittings for tubes are detailed in three bulletins of the Aircraft Fitting Co., 1400 East 30th St., Cleveland 14, Ohio. The bulletins cover pipe and hose fittings (P-200); flared tube fittings (J-100); all-purpose flareless fittings (F-10). All bulletins contain illustrations, specifications and prices.

•

A High-Styrene, copolymer rubber pail with a handle of similar material, designed for pouring into narrow-necked vessels and for tight-fitting lids is being produced by American Hard Rubber Company, 11 Mercer St., New York 13, N. Y. The pail has resistance to a long list of corrosives and is chip or crack proof and easy to clean.

Identification of pure and alloyed metals through use of the inherent differences in their surface films is said to be possible at rates up to 1000 per hour with "Electrospot," a self-powered portable device manufactured by Electrochemical Instrument Laboratory, 532 Woodland Ave., Mountainside, N. J. Identification of small items is accomplished by dipping a portion of the material in an electrolyte, and for large items by pressing a test probe against the material. Reading a dial setting after rotation to a zero deflection on a millivolt meter identifies the metal. The device may be used to identify and sort metals in any form rapidly and nondestructively.

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All-weather, one-man inspection rectifiers for cathodic protection installations offered by Control Corp., Dept. C, 717 Central Ave., N. E., Minneapolis, 14, Minn., include the following features: fast, safe 8-step voltage adjustment without shutting down unit; high inverse voltage protection, up to 36 volts; removable bug-screen, convection cooled, automatic high temperature cut-out reduces output to half rated value during periods of excessive heat; sustained meter accuracy because meters are automatically disconnected except during readings; seven sizes of panel fit one size cabinet, recording meter terminals in unit's DC circuit.

Corrosion Abstracts

TESTING

• Instrumentation

2.4
Testing Materials by Ultrasonic Visual Methods. R. Pohlmann. *Tecknik*, **3**, No. 11, 465-470 (1948).

A universal ultrasonic visual equipment for testing small work-pieces (spot welds) as well as big sheets, and its application to testing under water, are described. The field of vision can be as much as $23\frac{5}{8}$ x 19-1/16 in. The pictures obtained by penetration are better than those by reflection. Flaws in materials are more exactly indicated than by X-ray testing, especially if the faults, cracks, or laminations lie parallel to the direction of the beams. Flaws 0.018 in. in dia. and 4×10^{-6} in. in thickness can be detected.—MA.

2.4
Metallurgical Inspection of Castings. R. R. Senz. *Foundry*, **77**, No. 6, 82-83+ (1949).

S. reviews destructive and non-destructive methods of inspecting castings. The former group includes break-up tests, chemical analysis, and the determination of mechanical properties from specimens taken from the castings, and microscopical examination. Non-destructive methods discussed include chemical analysis and the tensile testing of separately cast specimens, fluoroscopic crack detection, radiography, and proof testing.—MA.

CORROSION ENVIRONMENTS

• Chemicals Inorganic

4.3, 7.2, 6.1, 6.2, 8.8
Heavy Chemicals in England and Wales: Alkali Inspector's Report for 1948. *Chem. Trade J.*, **125**, 211-213 (1949) Aug. 19.

Reference is made to acute corrosion in sulphate of ammonia plants, particularly in portions following evaporation and in concentrated liquor plants. Ammoniacal liquor produced by the newer and more intensively worked coke ovens appears to have more corrosive properties than that from coke ovens operated at comparatively low temperatures. Stainless steel has been tried in place of cast iron for vapor and condenser pipes but with disappointing results. Trials of aluminum alloys are also being made. This corrosion problem is acute, and it would seem that more research should be directed to finding a satisfactory resistant material.—INCO.

4.3, 7.4, 7.6, 8.8
Corrosion. M. G. Fontana. *Ind. and Eng. Chem.*, **40**, No. 11, 87A-88A (1948) Nov.

Description of corrosion problems frequently encountered in contact sulfuric acid plant equipment includes contact plant equipment, blowers, heat exchangers and absorbers and coolers.—INCO.

4.3, 4.1, 1.8
Processes of Drop Corrosion of Aluminum. I. Corrosion of Aluminum in Contact with Droplets of Solution of Salt Without Additions of Free Acid. I. V. Krotov and T. M. Khachadurova. Bulletin of the Academy of Sciences of the USSR, Section of Chemical Sciences (Russia) **1949**, 18-26, Feb.

Investigated using copper and silver salts. The characteristic role of the oxygen in the air in relation to these processes is discussed. Experimental results from the thermodynamic point of view are given.—MA.

4.3, 6.1, 6.2
Hypochlorites as Sanitizers. M. A. Lesser. *Soap Sanit. Chemicals*, **25**, No. 8, 119+ (1949) Aug.

Chlorine sanitizers do not affect glass, stainless steel, or most non-metallic materials, but they have a tendency to corrode tinned iron, copper, nickel and other metals. Chlorine sanitizers are potent bleaching agents.—INCO.

4.3, 6.2
Corrosion of Powdered Copper. A. I. Levin and A. V. Pomosov. (In Russian.) *Zh. Prikladnoi Khim.*, **22**, No. 6, 592-599 (1949) June.

Experiments using commercial powder (99.56% copper) indicate there is relatively little corrosion in moist air or in dry CO_2, SO_2 or NH_3; rapid attack occurs with moist gases. With hydrogen chloride, however, the corrosion is initially much greater in the dry gas; an explanation for the anomaly is proposed. Measurement of corrosion in the presence of dry and moist ammonium chloride and ammonium carbonate are also reported; considerable attack was caused by the latter substance.—BNF.

4.3, 3.4, 6.1, 6.2
Fluorine Progress. R. W. Porter.

Chem. Eng., **55**, No. 4, 102-105 (1948) April.

In a discussion of the research and development of flourine, mention is made of low carbon steel, copper, magnesium, nickel and monel as metals that are not corroded by it at moderate temperatures. With these metals an adherent fluoride film gives necessary protection to base metal.—INCO.

4.3, 5.3, 6.2

A Staff-Industry Collaborative Report —Modern Production of Chlorine and Caustic Soda. W. H. Shearon, Jr., with F. Chrencik and C. L. Dickinson, Diamond Alkali Co. *Ind. & Eng. Chem.,* **40**, No. 11, 2002-2010 (1948) Nov.

Discussion of raw materials, chlorine production, caustic preparation, hydrogen chloride, filling and storage systems, and instrumentation and safety. Among materials chosen as best compromise on basis of corrosion resistance and cost is nickel-clad equipment for handling hot caustic. For storage purposes, nickel-lined tanks are used for 73% caustic.—INCO.

• Chemicals Organic

4.4

Action of Aluminum on Ethyl Bromide. D. A. Pospekhov and N. N. Atamanenko. *J. of General Chemistry,* **18**, No. 7, 1319-1321 (1948) July. *(Guide to Russian Scientific Periodical Literature),* **2**, No. 4, 129 (1949) Apr.—ALL.

4.4, 5.4

Abrasion and Acid Resistance of Por-
celain Enamels. *Product Eng.,* **40**, No. 8, 126 (1949) Aug.

Effects of acid pretreatment of porcelain enamels on acid resistance and abrasion resistance of treated specimens showed that treatment with acetic acid inhibited further attack by citric acid. This is explained on hypothesis that acetic acid and butyric acids preferentially leach alkalies from enamels surface, leaving behind a silica-rich film that is resistant to further solution even in citric or stronger acids. Effect of abrasion was sufficient to reduce rating on some enamels from a good Class B by standard test to a poor Class C by same test modified to include abrasion treatment. Results suggest that titanium-type enamels are sensitive to these effects and that routine inspection tests should be made in regular production to assure that composition and processing of enamels are maintained at optimum conditions.—INCO.

• Soil

4.5, 5.4, 5.2

Gas Stored at High Pressure in Underground Pipe Sections. D. V. Meiller, Public Service Co. *Heat., Piping & Air Cond.,* **20**, No. 5, 93-97 (1948) May.

Reasons for and methods of utilizing high pressure storage of natural gas in pipe sections buried underground, storage consisting of lengths (about 40 ft.) of 24 in. OD, seamless, high carbon alloy steel pipe. Pipes were coated with Bitumastic and wrapped with asbestos felt for corrosion protection. Magnesium anodes were installed for cathodic pro-.

tection, to be replaced periodically. Gas graphs and pipe diagrams are shown.—INCO.

PREVENTIVE MEASURES

• General

5.1, 8.2

The Protection of (Architectural) Metals Against Corrosion. T. P. Hoar. *J. Royal Inst. Brit. Arch.,* Third Series **56**, No. 6, 276-281 (1949) April.

A paper to the Architectural Science Board, RIBA. A discussion in simple terms of corrosion and protection of metals used in architecture.—BNF.

• Cathodic Protection

5.2

Cathodic Protection: A Symposium. Electrochemical Society and National Association of Corrosion Engineers. Book, 1949, 203 pp. National Association of Corrosion Engineers, 905 Southern Standard Building, Houston 2, Texas, $8. ($6 to members of either Society.)

At this joint symposium between the above American societies, held in December, 1947, twenty-three papers were read, reviewing basic principles of cathodic protection and its application to corrosion control. The papers (here printed with discussions) were as follows: R. H. Brown and G. C. English, "Electrochemical Principles of Cathodic Protection (pp. 7-11); M. C. Miller, "Characteristics and Field Use of Elec-

trical Instruments for Corrosion Investigations and Cathodic Protection" (pp. 12-33); P. Fugassi, "Characteristics of Half-Cells Used as Reference Electrodes" (pp. 34-36); R. B. Mears and J. M. Bialosky, "Laboratory Methods for Determining the Current Density Required for Cathodic Protection (pp. 37-46); N. P. Peifer. "Current Required for Cathodic Protection" (pp. 47-53); F. B. Fry, "Detection, Measurement and Mitigation of Stray-Current Electrolysis" (pp. 54-56); L. R. Sheppard, "Detection and Measurement of Currents Other Than Stray Currents, including Magnetic Earth Currents" (pp. 57-65); L. B. Nelson, "Coordination of Cathodic Protective Installations to Avoid Interference with Adjacent Structures" (pp. 66-72); F. A. Waelterman, "Use of Rectifiers as an External Source of Protective Currents" (pp. 73-76); M. L. Jacobs, "Use of Wind-Driven Generators as an External Source of Protective Currents" (pp. 77-79); D. B. Good, "Economic Factors Bearing on Application of Cathodic Protection" (pp. 80-87); D. Holsteyn, "Locations and Materials for Anodes for Impressed Current" (pp. 88-92); G. R. Olson and C. W. Evans, "Relative Merits of Various Cathodic Protection Current Sources" (pp. 93-96); E. A. Anderson, "Physical and Chemical Characteristics of Zinc Anodes" (pp. 97-100); E. D. Verink, K. K. Reid and E. R. Diggins, "Current Output of Light Metal Galvanic Anodes as a Function of Soil Resistivity" (pp. 101-103); H. A. Robinson, "Fundamental Characteristics of Magnesium Galvanic Anodes" (pp. 104-113); H. W. Walquist and H. M. Fanett, "Practical Use of Galvanic Anodes" (pp. 114-143); I. A. Denison and W. Romanoff, "Behavior of Experimental Zinc-Iron Couples Underground" (pp. 144-157); T. P. May, G. S. Gordon and S. Schuldiner, "Anodic Behavior of Zinc and Aluminum-Zinc Alloys in Sea Water" (pp. 158-171); L. J. Gorman, "Corrosion and Protection of Underground Power Cables" (pp. 172-184); F. J. LeFebvre and L. P. Sudrabin, "Effect of Environment Characteristics on Cathodic System Design" (pp. 185-188); G. Corfield, "Relations between Protective Coatings and Cathodic Protection" (pp. 189-191); H. J. McDonald and J. T. Waber, "Cathodic Protection in the Control of Stress Corrosion Cracking" (pp. 192-203).—BNF.

5.2, 4.6, 4.5, 8.3

Special Anodes for the Cathodic Protection of Water Tanks. A. L. Kimmel. *Corrosion*, **5**, No. 7, 217-220 (1949) July.

Recent experimental work undertaken by the author and by others in the field of water tank protection indicates that anodes constructed to contain a source of magnesium ions can be used to provide very efficient cathodic protection in fresh water systems. Protective films of magnesium hydroxide are formed rapidly on the cathode at low current densities, and current flow maintains the oxide film on the surface to be protected. The experimental procedure was as follows: cathode coatings were formed at the current density necessary to protect iron under the prevailing conditions —this value being obtained by a Britton curve for the city tap water of Gainsville, Florida—and it was assumed that a drop in cathode potential of —0.2 volt would be sufficient; after oxide film formation, the cathode current was decreased to lower values and observations over a period of three months de-

termined the extent of protection obtained. Results of the experiments carried out by this procedure are tabulated. Graphs, photographs, and six references are included.—ALL.

5.2, 4.6

Anodic Behavior of Zinc and Aluminum-Zinc Alloys in Sea Water. T. P. May, G. S. Gordon and S. Schuldiner. Cathodic Protection Symposium (Electrochemical Society and National Association of Corrosion Engineers), 1947 (published 1949), pp. 158-171.

Investigation of the behavior of various grades of zinc and of aluminum and aluminum-zinc alloys containing aluminum from 4% upwards for cathodic protection of steel in sea-water. Information is given on the nature of the corrosion products found in the zinc anodes. —BNF.

5.2, 3.5

Cathodic Protection in the Control of Stress Corrosion Cracking. H. J. McDonald and J. T. Waber. Cathodic Protection Symposium (Electrochemical Society and National Association of Corrosion Engineers), 1947 (published 1949), pp. 192-203.

The mechanism of cathodic protection as it applies to stress corrosion is reviewed. A number of instances of prevention of cracking by cathodic protection are discussed.—BNF.

5.2

General Aspects of Cathodic Protection Application and Installation to Pipe Lines. R. H. McLeod. *Amer. Gas J.*, **170**, No. 3, 34-35 (1949).

Describes two techniques, the use of anodes of magnesium or zinc, and the application of electric current from an external source, in order to protect gas pipe lines from corrosion.—MA.

5.2

The Mechanism of Cathodic Protection. R. B. Mears. *Metaux et Corrosion*, **23**, Nos. 271-272, 50-56 (1948) Mar.-Apr.

R. Mears presents a well-illustrated general article on the subject of cathodic protection, giving the theory and the progress of the study and various applications.—ALL.

5.2

Fundamental Characteristics of Magnesium Galvanic Anodes. H. A. Robinson. Cathodic Protection Symposium (Electrochemical Society and National Association of Corrosion Engineers), 1947 (published 1949), pp. 104-113.

A full account of the factors affecting the behavior of magnesium anodes used for cathodic protection.—BNF.

5.2, 4.6

Principles of Cathodic Protection Design (Use of Aluminum, Magnesium and Zinc Anodes). L. P. Sudrabin and F. P. MacDonald. *J. of the AWWA*, 40, No. 5, 489-494 (1948).

The use of aluminum and magnesium for galvanic anodes is discussed.—ALL.

5.2

Practical Use of Galvanic Anodes. H. W. Wahlquist and H. M. Fanett. Cathodic Protection Symposium (Electrochemical Society and National Association of Corrosion Engineers), 1947 (published 1949), pp. 114-143.

Discusses the use of zinc, magnesium and aluminum anodes under various conditions.—BNF.

5.2

First Steps in Installing Cathodic Protection. *AGA Monthly*, **31**, No. 4, 32+ (1949) Apr.

Importance, cost, and advisability of installing cathodic protection discussed. Preliminary steps necessary for its application to a gas distribution system are outlined.—INCO.

5.2

How to Select Materials for Cathodic Protection Against Corrosion. N. B. Bagger. *Mat. & Meth.*, **30**, No. 7, 47-49 (1949) July.

Intelligent use and selection of galvanic anodes, or waster plugs greatly reduces electrolytic corrosion in many types of equipment, therefore reasons for selection of magnesium, aluminum, steel or iron are given.—INCO.

5.2

The Environment in Relation to Cathodic Protection of Underground Pipes. *Indus. Fin.* (Lond.), **1949**, 502-503, Mar.

Presented at the American Gas Association 1948 Joint Production and Chemical Committee Conference.—MA.

5.2

Cathodic Protection of Steel in Various Chemical Solutions Using Magnesium, Zinc and Zinc-Lithium Anodes. R. R. Roger and W. R. G. Stewarts, Bureau of Mines. Paper before Can. Inst. of Mining Met., Ann. Gen. Mtg., Quebec, Apr., 1949. *Trans. Can. Inst. of Mining Met.*, **52**, 107-110 (1949). *Can. Mining Met. Bull.*, **42**, No. 445, 218-221 (1949) May.

Investigation to obtain the value of pure magnesium and pure zinc as anodes for the cathodic protection of steel in acid, neutral, and alkaline solutions of 6 different sodium salts. Results give the average anode corrosion rates and the degree of protection of the steel cathodes. The zinc-lithium alloy anode was found superior to pure magnesium and

pure zinc in certain low pH salt solutions. Accompanying photographs show corrosion inside steel cylinders.—INCO.

• Metallic Coatings

5.3

Corrosion Tests on Hard Chromium Deposits. (In German.) Walter Eilender, Heinrich Arend, and Franz Sadrazil. *Metalloberfläche,* **3,** 32-35 (1949) Feb.

Shows that the resistance of hard chromium is caused by its being passivated in air. Investigates the effects of surface condition, heat treating, nitrite, paraffin, and phosphate baths (both before and after the chromium-plating operation) on the corrosive properties of chromium. Data are tabulated.—BLR.

5.3

Metals. Korrosionsuntersuchungen an Hartchromschichten (Corrosion Investigations on **Hard Chromium Layers**). Arend, Heinrich, and Franz Sadrazil. (PB-74662, Frames 8467-8471).

Report from the Institut für Eisenhüttenkunde der Technischen Hochschule, Aachen, Ger.

The corrosion stability of hard-chrome coatings on iron and steel is due to passivation in air, causing the coated metal to behave like a noble metal. Effective chromium coatings must be dense, i.e., nonporous. The thickness required, usually 0.02-0.04 mm, depends on the corrosive medium, e.g., sea water requires a thicker coating than air.

Corrosion resistance can be influenced by controlling the conditions of coating deposition to produce finely grained, continuous, homogeneous films. A very smooth surface, which can be obtained by anodically polishing the base metal, increases the resistance of the chromium coating or diminishes the thickness otherwise required. Heat treatment, on the other hand, impairs the corrosion behavior, probably by widening the crazing network of the coating.

Corrosion resistance in sea water is decreased by phosphating the metal either before or after the chromate coating is applied, but is not affected by treating the finish in a nitrate or paraffin bath.

5.3

Lead Coatings on Steel. J. L. Bray. *Metals Handbook, ASM,* **1948,** 706-707.

Methods of hot dipping in molten lead and various alloys are described. The advantages and disadvantages of lead as compared with zinc and tin coatings are briefly discussed.—MA.

5.3

Electroplated Metal Coatings. William Blum. *Metals Handbook, ASM,* **1948,** 716-720.

B. discusses the selection, testing, and applications of plated coatings and gives typical bath compositions and conditions for depositing the common metals. 21 references are given.—MA.

5.3

Nickel- and Nickel-Alloy-Clad Steels. W. G. Theisinger and F. P. Huston. *Metals Handbook, ASM,* **1948,** 547-548.

The properties, treatment, and joining of the clad steels are dealt with.—MA.

5.3

Hard-Facing by Metal Spraying. *Welding Eng.,* **33,** No. 3, 62, 64 (1948) Mar.

Sprayweld is a new method developed to apply thin, hard, uniform layers of alloy-to-metal facings. In the process a wire consisting of fine particles of alloy imbedded in a plastic binder is used in a standard metallizing gun. During the operation the plastic is completely volatilized so that the deposit consists only of the metallic constituent. The base metal is then fused with the same gun at 1850-1875° F resulting in a uniform coating alloyed to the base. This layer is physically and chemically identical with a hard facing of the same alloy produced by other means. The wetting properties of the alloy makes it possible to obtain fusion to iron, plain-carbon steels. Monel, nickel, and copper. No flux is required since a high resistance to oxidation is inherent in the alloy and the base metal is protected by the sprayed coating.

Dilution of the surfacing metal is kept to a minimum by the relatively low-melting point of the alloy and the short fusing time. This gives optimum erosion and corrosion resistance. Although the sprayed alloy melts at 1850° F it is not completely fluid under 2050° F. This range of plasticity allows a controlled thickness to be sprayed on a limited area and the coating to be fused without changing the contour of the hard-facing layer.

A spraywelded surface having a hardness of 58 Rockwell C will often resist wear ten times longer than carburized or nitrided surfaces of greater hardness. Hardfaced surfaces free from cracks or dilution of the surfacing alloy are resistant to a wide variety of acids and salts as well as to heat corrosion. Coatings thinner than 0.010 in. should not be used except where only mild corrosive conditions are likely to occur.

The process is especially suitable for cylindrical parts that may be sprayed and fused as they are rotated; these show little distortion. It is not applicable where heavy coatings are required. Neither is it practicable for highly stressed parts which were originally heat treated to develop the correct physical properties until it has been determined that the heating cycle will have no serious effect.—PDA.

5.3, 5.2

Zinc in the Protection of Mild Steel in Plant Construction. B. Walters. *Int. Chem. Eng. and Proc. Ind.,* **30,** No. 5, 224-7 (1949) May.

Reliable information on the applications of zinc coatings for the protection of mild steel against corrosion. There are short descriptions of all the five processes available and comments on the uses to which they are best suited. As a zinc coating is frequently used as a basis for paint, the correct painting treatment for zinc coated surfaces is explained. The article concludes with sections on the use of zinc dust paints for restoring severely weathered galvanized surfaces, and the protection of underground pipe lines by zinc anodes.—PDA.

5.3, 4.4, 7.6

Metallizing: How They Put It to Work in Chemical Plants. J. E. Wakefield, Metallizing Eng. Co. *Chem. Eng.,* **56,** No. 7, 96-97 (1949) July.

To solve problem of a 6300 lb. stainless steel chill roll for an animal fat rendering plant, stainless steel was sprayed on a straight cast iron roll. Discussion explains how this was done. When it comes to surfacing freeze rolls, chill rolls and similar processing equipment, metallizing is at its best in high speed and low cost. Monel, stainless steel, nickel or Ni-chrome can be applied to cast iron, steel, or other metal bases. Tin-coating alcohol tanks, and restoring a plug cock are also discussed.—INCO.

5.3

Designing With Metallized Structures. J. E. Wakefield. *Prod. Eng.,* **20,** No. 5, 117-121 (1949) May.

Metals applied by wire-type spray guns give specialized properties in local areas and to be successful, these metals must be sprayed over properly prepared surfaces. Metallized coatings of aluminum on cloth are used in production of radio capacitors, giving advantages of high capacity ratio, reduction in size, and stronger tabs for electrical connections. These special aluminum tabs are inserted in the fabric before it is metallized. Metallizing is also applied for resistance to heat oxidation. By this means, melting crucibles, annealing covers, pyrometer tubes, salt pots and similar equipment can be effectively protected. The process consists mainly of the application of aluminum, special alloys and a proper sealer. While articles so treated will not equal the life of alloy parts they will outlast unprotected steel parts many times, giving a compromise between cost and extreme length of life. It is also possible now to apply coatings of hard, wear-resistant steels or stainless steel to aluminum or magnesium bases. It seems likely, therefore, that the use of both will greatly increase in the near future, especially for lightweight and wear-resistant parts.—ALL.

5.3

How to Select Sprayed Metals. J. E. Wakefield, Metallizing Eng. Co. *Am. Machinist,* **93,** No. 15, 80-82 (1949) July 28th.

Discussion includes common characteristics, individual metals such as bronzes, nickel and nickel-alloys, and applications of spraying metals. Sprayed metals offer better protection against wear and corrosion at a lower cost. Chart indicating comparative shrink rate of sprayed metals includes 18-8 stainless steel.—INCO.

5.3

Methods of Tinning Cast Iron. Pierre Tyvaert, *Fonderie,* **27,** 1099-1100 (1948); *J. Iron Steel Inst.* (Abs.), **161,** 159 (1949).

Practical notes are given on the tinning of cast iron by the hot-dip process and by electrolysis.—MA.

5.3

Tinning of Steel. Robert J. Nekervis and Bruce W. Gonser. *Metals Handbook, ASM,* 709-712 (1948).

The manufacture of hot-dipped and electrolytic tinplate is described. The tinning of wire, thin strip, cast iron and fabricated articles is also dealt with.—MA.

5.3

Some Characteristics of Sprayed Metal. G. Tolley, Metallisation, Ltd., Dudley, Eng. *Metallurgia,* **38,** 263-266 (1948) Sept.

Some salient features of metal-sprayed deposits are outlined. The value of sprayed metal coatings for building up

worn parts and for protecting against corrosion is now well established.

Before spraying metal coatings onto any material, whether metal, wood, or plastic, it is necessary to prepare a roughened surface to ensure good adhesion. This is usually accomplished by grit-blasting. For special purposes, such as building up work, grooving or knurling may be used to obtain a deposit having a high resistance to shear.

Adhesion tests are of value in showing that metal-sprayed coatings will satisfactorily adhere to the base metal. Bend tests have little significance in relation to adhesion, though they may be of use where a material has to undergo considerable distortion after spraying. Generally, a steel sheet sprayed with a metal coating under 0.004-in. thick can be bent through 180° without the coating cracking off. Above this thickness it will begin cracking when bent through angles less than 180°.

The hardness of sprayed metal is different from that of the cast or wrought metal. Its porosity causes a lower indentation hardness than the original metal in massive form, but its oxide content produces a higher scratch hardness.

When considering sprayed deposits, the particular properties afforded by the spraying procedure must be taken into consideration. The structures of deposits produced by the wire and molten-metal processes are usually nearly indistinguishable, but the powder process yields a structure which is considerably different. With the powder process oxide content and porosity are generally higher, giving rise to important structural differences.

Reclaiming worn parts by metal spraying offers distinct advantages over reclaiming by welding and heavy electroplating. Only very slight wear occurs in built-up parts because porosity of the deposit results in the retention of a tenacious oil film giving rise to excellent lubrication.

A sprayed metal coating of 0.004-0.005 in. presents an impermeable barrier protecting against corrosion. These coatings are replacing the older method of weathering, wire brushing, and use of red-lead primer as corrosion protectives. Sprayed coatings also provide an excellent surface for paint; a sprayed coating plus a finishing paint provides protection achieved by few other systems.—PDA.

5.3

The Plating Step in Clad-Steel Manufacture. Albert D. Taylor. *Plating,* **36,** No. 3, 239-245 (1949).

Describes briefly the use of nickel plate as a bonding agent between stainless steel or Inconel cladding applied to mild steel. Such plating is not required for bonding nickel or Monel metal. Nickel plating is used because it forms no brittle layer between the steel and the cladding metal, and it also acts as a barrier against carbon diffusion into the cladding metal. It ensures good heat-transfer properties between the steel and the cladding. Brief details of the plant used for plating the cladding metal and of the operations employed are presented. A 2-hour plating cycle is used, to give a total thickness of nickel of 0.005 in. After plating the cladding is placed in contact with the grit-blasted steel, a similar assembly, but reversed, is set on top of the first, separated from it by an infusible parting compound, the whole sandwich sealed by welding, soaked

at 2100°-2350° F (1149°-1288° C) and then rolled. As a result of the nickel-plating operation, fabricating operations such as shearing, bending, flanging, forming, riveting, or welding can be performed without affecting the bond. The bond will also withstand considerable thermal shock, in spite of the different coefficient of expansion of the steel and the cladding metal.—MA.

5.3

Metallizing in Relation to Marine Engineering. J. B. Stiles. *Trans. Inst. Marine Eng.,* **60,** No. 12 (1948). *Welding J.,* **28,** No. 6, 541-558 (1949) June, Disc., ibid, 659-669 (1949) July.

Discussion stresses both limitations and usefulness of metal spraying in shipwork. Equipment used to spray metal, characteristics of coating produced, methods by which bonding to base material is achieved and techniques for finishing sprayed metal coatings are discussed. Applications of process to marine engineering are divided into (a) reclamation of worn parts, and (b) protective coatings to resist corrosion. Discussion of protective coatings includes theory of corrosion, finishes applied subsequent to spraying, steel hulls and protection of miscellaneous parts.—INCO.

5.3

Metal Spraying—What It Is . . . What It Does . . . How It Is Done. M. J. Rowan. *Am. Mach.,* **93,** No. 10, 107-118 (1949) May 19.

Discussion of nature of sprayed metal and conditions under which it may reasonably be expected to give good service, equipment needed for process, and steps required to produce good coatings. One of major fields for metal-sprayed coatings is protection of a base metal against corrosion. Other uses of metal spraying are to repair castings which have blow holes or surface defects for protection against high temperatures and spraying plastics.—INCO.

5.3

Flame Spraying of Metals and Plastics in Engineering and Shipbuilding. F. A. Rivett. Paper before Institution of Engineers & Shipbuilders, Scotland. *Can. Metals Met. Inds.,* **12,** No. 6, 27-28 (1949) June.

Discussion includes zinc coatings, zinc and paint, and lead spraying. Zinc coatings prevent marine corrosion as shown by examples. Lead spraying is used to protect steel under mildly acidic condition. Of fused plastic coatings, Polythene, which has good electrical insulating properties is unaffected by acids and alkalies up to 80° C. It is used as protective coating for chemical plant.—INCO.

5.3

Prevention of Corrosion on Steel. I. Richards. *Org. Fin.,* **9,** No. 9, 33-4+ (1948).

The protection required by steel depends to a large extent on the exposure conditions. Wherever it is likely to rust, even if an organic coat is applied, it should receive a metal coating. Zinc is the main coating metal and methods of applying it to steel are briefly described. —ZDA.

5.3

Sprayed Iron and Steel Coatings on Light Metals. *Revue de l'Aluminium,* **25,** 361 (1948) Nov.

An exhaustive investigation has been

carried out in France in co-operation with official bodies into the possibility of providing light metals with protective coatings of iron or steel. A large range of ferrous coatings extending from soft iron coatings to 18-8 stainless steel and 13 percent chromium iron was produced on aluminum surfaces by the spray method. It was found that the layers produced by spraying adhered solely by mechanical action, no alloying between the spray metal and the light metal being produced. The iron coatings possess a certain porosity and appear to have certain self-lubricating properties, with the friction coefficient being smaller than that found for the same ferrous material in rolled form. Coatings of this type are claimed to impart to light metal, which may be aluminum or magnesium alloy, a surface wear comparable with that of a corresponding steel surface.—TIME.

5.3

Zinc Coatings. W. M. Peirce. *Metals Handbook, ASM,* **1948,** 712-714.

Galvanizing is the most commonly used of all methods of metallic protection of steel. The production and properties of hot-dip coatings are described, and there is brief mention of electro-galvanizing.—MA.

5.3

Hard Chrome Plating on Light Alloys. J. Patrie. *Revue de l'Aluminium, F.,* **25,** No. 149, 335-338 (1948) Nov.

Chrome plate, previously used only on iron and steel, is now being extended to light alloys. Hard chrome plate differs from ordinary chrome plating principally by the thickness of the chrome deposit which is in the range of 20μ to 0.1 mm. for hard chrome and several μ for ordinary chrome. Results of chrome plating a nickel-plated aluminum alloy in an ordinary chrome plating bath were unsatisfactory. It was decided to plate directly on the aluminum as a coating of zinc, copper, etc., would be too porous to support a chromium film. The problem remained of finding a satisfactory surface preparation capable of eliminating the natural oxide film and at the same time, creating a surface favorable to the mechanical clinging of the chromium deposit. A chemical pickling solution was found to give the best results, consisting of an acid such as hydrochloric, hydrofluoric, etc., and containing the salt of heavy metal such as nickel or maganese. There are two types of solutions:

(1) After degreasing and rinsing, the articles are immersed in a solution of $NiCl_2$, HF, H_2SO_4 at 25-30° C (77°-86° F) until the evolution of gas brought about by the attack of the bath on the light alloys diminishes in intensity. The surface is then more or less uniformly coated with a nickel deposit which dissolves after a rapid rinse in a solution of nitric acid at 36° Be. When the hydrogen evolution terminates, usually about 30 seconds, the articles are removed from the bath, washed in running water and dried, before chrome plating. Generally, this type of solution gives good results on pure aluminum alloys containing magnesium such as Duralinox. Magnesium and silicon such as Almasilium, but it is not suitable for duralumin types. Better results are obtained with chill cast than sand cast articles due to the porosity in sand castings.

(2) The second solution is composed

of HCl and MnSO$_4$ at 40° C (104° F) for one minute. When the object loses its yellow color following the precipitation of manganese and becomes dark grey it should be removed from the bath. The manganese deposit is dissolved in a bath composed of 3 parts HNO$_3$, 1 part of 50% HF and at 20° C (68° F) for several seconds.

In comparison with the first solution, on Duralinox and Almasilium, the second solution does not give such good results on casting alloys but gives better results on forging and sheet. It also is not suitable on alloys of the duralumin type.

The following composition of chrome bath gives the best results: chromic anhydride, 250 g/l, H$_2$SO$_4$ 1.25-2.5 g/l. The deposits have a maximum adherence when produced at 50-60° C (122-140° F) with a current density equal to 40 A/dm^2. The thickness of the chrome deposit will be in the order of 20-25 μ per hour. It is necessary to commence the electrolysis under a very high c.d. (60-80 A/dm^2), the hydrogen overvoltage on aluminum being very weak, and the surface very rough, when the d.c. can be reduced to normal value when the object is covered with a thin coating of uniform chromium which is generally obtained in several minutes of electrolysis.

The role of corrosion inhibitor of the chromium on the aluminum is well known and the absence of very electropositive coatings, such as copper, between the light alloy and the deposit of chromium diminishes many corrosion risks. Deposits of several μ have shown remarkable protection against attack of alkalis on aluminum. One common cause of corrosion is the presence of cavities which entrap the electrolyte and create an electrochemical action between the different components of the base metal which separates the deposit from the base.—ALL.

5.3

Metal Spraying. E. A. Williams. *Mining J.*, **232**, No. 5934, 352-354 (1949) May 14.

Modern spraying techniques make use of two different forms of raw metal, metallic powder and wires: the Mark 16 spraying pistol utilizing wire, and the Schori pistol powder. Both process, as well as equipment involved, are described. Zinc and aluminum coatings, building-up processes and decorative work are discussed.—INCO.

5.3

Stainless Steel Clad Sheets. *Rev. Sci. Instruments,* **20**, No. 5, 380 (1949) May.

Permaclad is a composite sheet material in which a layer of stainless steel is permanently bonded to a carbon steel backing plate. The stainless layer forms 20% of total thickness in sheets up to 13 gauge, and 10% in heavier gauge. Cost of material is about half the cost of solid stainless in the same gauge. The bond strength is said to be equal to that of component steels. The clad material is metallurgically correct on one side for corrosion-resistant service, and possesses the ductility and other desirable properties of the carbon steel backing plate. The standard material (Type 304 stainless with AISI-1008 backing) can be cold-formed, arc- or spot-welded, soldered, drawn, or stamped without separating the layers and without loss in the corrosion-resistant properties of stainless steel. Compositions other than the standard may be specified.—INCO.

• Non-Metallic Coatings

5.4

Corrosion: Surface Protection of Iron and Steel. *Iron and Steel,* **22**, 93 (1949) Mar.

Describes Detel Metal Undercoat invented by F. C. Dyche-Teague, Technical Director of Detel Products, Ltd., Greenford, England. It is stated that the protective action does not depend on the medium or bond material used, but on the pigment itself.—BLR.

5.4, 7.2, 7.6

Phenolic Resin Coatings Baked by Induction Heating. Allen G. Gray. *Prod. Fin.,* **12**, No. 7, 74+ (1948) Apr.

Induction heating of the thermosetting phenolic coatings on metals is superior to conventional baking methods since its shortens the curing time without lowering the quality of the coating. The exact temperature control inherent in induction heating is of additional advantage in curing multiple coat systems.

One example of an application of induction heating is the continuous coating and curing of phenolic resins on pipe. This process involves continuous passage of a sand-blasted pipe through a tank of the coating solution, and then through the electromagnetic field of a system of induction heating coils actuated by low-frequency alternating current. The pipe section is rapidly brought to the desired curing temperature, e. g., to 350° F within 5 minutes at a power input of only 400 watts. The baking time can be reduced by increasing the amount of power supplied; the total curing time also depends on the reactivity and heat resistance of the coating, and upon the rate at which the pipe travels. Conventional baking times are 20-60 min. at 275-400° F in electrical or gas-fired circulating air ovens, infrared baking units, or a combination type of gas-fired and infrared equipment.

Boiler tubes protected by phenolic-resin baking coatings withstood exposure to boiling water at 212° F on the outside and heat radiation at 675° F in the inside. Steel pipes coated with phenolic resins were practically unaffected by an exposure of 4-6 yr. in corrosive soils and retained high gloss after cleaning.—PDA.

5.4, 4.3, 4.6, 3.5

Corrosion-Proofing Simplified. J. R. Fisher, Jr. *Steel,* **124**, No. 17, 80-82 (1949) Apr. 25.

Industrial Metal Protectives, Inc., in conjunction with Commonwealth Engineering Co., has developed a liquid zinc-content coating called Zincilate which can be applied to metals like a paint. The coating will protect the surrounding exposed metal when these areas are not excessive, so that pinholes or ruptures will not offer a foothold for corrosion. Treated parts show no film failure after 1000 hours at standard ASTM salt spray exposure at 90° F (32.2° C) and with 20% solution. Non-porous coatings show no failure in a 3600-hour weatherometer tests. The material is unaffected by mild acids and alkalies, hot water up to 150° F (66° C) and at temperatures up to 600° F (316° C). Surface of the metal must be thoroughly cleaned before coating. Coverage of the material is approximately 400 square feet per gallon. Can be baked or air dried.—ALL.

5.4

Building Organic Protective Coatings to Special Requirements. K. G. Compton. *Corrosion,* **5**, No. 5, 148-150 (1949) May.

Mass-production manufacturing schedules and special design requirements have created an increased demand for metal paint products based on synthetic resins combined with drying oils. The many ways in which these organic protective coatings can be "tailored" to fit the need of the user are outlined. It is demonstrated that organic coatings, in order to provide maximum protection to the metals, must adhere well, be hard and tough enough to withstand impact and scraping, have flexibility, and include such environmental factors as moisture or chemical fumes. The compromises that must be made among the physical properties to obtain the proper balance are discussed. Examples are given of organic finishes which have been specially constructed.—TDD.

5.4

Corrosion Resistant Cement Production. *Chem. Eng.,* **54**, 110-111 (1947) June.

Equipment and procedures for manufacture of special resin cements at Natrona, Pa., by Pennsylvania Salt Mfg. Co., are described briefly and illustrated. —BLR.

5.4, 4.3

Protective Coatings. *Chem. Eng.,* **56**, No. 3, 252 (1949).

Proprietary coatings give very variable results when exposed to HCl. A table is given showing the performances of some of these coatings.—RPI.

5.4, 4.3

Corrosion Resistant Coating. *Chem. Eng.,* **56**, No. 3, 172, 174 (1949) Mar.

A line of corrosion resistant plastic coatings for protection of machinery, processing equipment and for general maintenance in factories where corrosives are used is known as Cyclon, series NPC. Cyclon is an inexpensive, easily applied, high solids synthetic paint that protects metals, wood, and ceramic surfaces against chemical attack by corrosive fumes, condensates and spillage. It air-dries quickly by solvent evaporation to an adhesive, hard-wearing, flexible, glossy coating without necessity of priming surface being coated. Coatings are unaffected by all alkalies as well as by salts and by most mineral acids. Developed by Poly-Cyclo Products Co.— INCO.

5.4

Undercoats and Primers Based on Alkyd Resins. L. Angelino. *Ind. della Vernice,* **2**, No. 12, 291-4 (1948).

Principles of their formulation are discussed: in general there should be 1 part of resin for every 2:5 parts of other non-volatile material in the paint. Formulae are given for some anti-corrosive primers and white undercoats.—RPI.

5.4, 2.5

Standard Specifications for Pigments. *ASTM Book of Standards,* Suppl., Pt. 11, 55-206.

Tentative specifications have been issued for the first time for copper phthalocyanine blue (D 963-48), copper powder for use in anti-fouling paints (D 964-48) and methods of testing para red and toluidine red pigments (D 97048). The

following specifications, formerly tentative, have been revised and adopted as standard: Raw and burnt umber (D 763-48), which now includes the subject matter of D 764 (burnt umber); raw and burnt sienna (D 765-48), which includes D 766 (burnt sienna). The following have been revised and relegated to the tentative status: pure para red toner, light (D 475-48), pure toluidine red toner (D 656-48), aluminum pigments, powder and paste for paints (D 962-48), a revision and consolidation of D 266 and D 474, test for acetone extract in black pigments (D 305-48), chemical analyses of dry cuprous oxide and copper pigments (D 283-48). The following have been revised without change of status: titanium dioxide pigments (D 476-48), sampling and testing aluminum powder and paste (D 480-48), red and brown iron oxide pigments (D 84-48), Venetian red (D 767-48), chemical analysis of zinc yellow pigment (zinc chromate yellow (D 444-48).—RPI.

5.4, 2.5

How to Specify Organic Finishes. A. L. Alexander, Naval Research Lab. *Prod. Eng.*, **20**, No. 7, 141-145 (1949) July.

Selection of properly designed organic coatings should be based on special requirements of material and product to be protected. Synthetic resin finishes find widest use on heavy duty electrical, mechanical, and chemical equipment. Discussion includes types of organic coatings, pigments, resin types, production requirements, film properties and applications. Photograph shows effect of painting with anti-fouling paint of a blend of chlorinated rubber and an acrylic resin.—INCO.

5.4, 4.2

Weather-Protective Treatment for Cotton Duck. American Association of Textile Chemists and Colorists. *Am. Dyestuff Reptr.*, **36**, 705-10 (1947); *Prev. Det. Abs.*, **5**, T 25-6 (1948).

Tests to evaluate the weather-protective properties of various resin and pigment finishes applied to cotton duck were made. Urea CH_2O used alone was successful. The incorporation of Pb chrome, Cr_2O_3, and phthalocyanine blue with urea/CH_2O, methyl methacrylate and oil-modified alkyds improved weather-resistance.—RPI.

5.4, 3.3

Mildewproofing Compound. S. S. Block. *Chem. Inds.*, **62**, 226-31 (1948); *Prev. Det. Abs.*, **5**, F 25-6 (1948).

A list of fungicides used in cellulosic fabrics, paints, leather, optical and electrical instruments, food and cosmetics is given with a short discussion on the efficiency of each.—RPI.

5.4, 3.3, 2.2

Submarine (Anti-Fouling and Anti-Corrosive Ships' Bottom) Paints Used by the German Navy in the 1939-1945 War. P. Colomb. *Ind. della Vernice*, **2**, No. 12, 286-90 (1948).

On the basis of personal experience in Germany during the war some minor corrections and augmentations are suggested to FIAT Final Report No. 681. —RPI.

5.4, 3.3, 2.2

Trials of Copper Paints and Antiteredo Compositions. Trials of Protective Paints on Wood. Reports from Ber-

muda and Malta, and Supplementary Reports from Bermuda. **Admiralty Corrosion Committee (Hull Sub-Committee) Reports ACC/H61/44; ACC/H79/45; ACC/H791/45.** *Prev. Det. Abs.*, **5**, W 65-6 (1948).

The results are given of tests on various anti-fouling compositions, including USN formula 16-X, painted out on wooden panels and submitted to marine exposure tests for 3 months and 6 months periods at Malta and 6 months and 1 year periods at Bermuda.—RPI.

5.4, 4.4, 4.3

Plastics and Rubber Derivatives as Anti-Corrosives. Anti-Corrosives in the Chemical Industry. F. G. Estartus. *Afinidad*, **25**, 390-8 (1948); *Brit. Abs.* B-II, 623 (1948).

The main factors to be considered in corrosion problems in chemical manufacture are indicated. Protective coatings include lacquers, vitreous enamels and synthetic resin linings. The psysical and anti-corrosive properties of synthetic resin lacquer films are described, including more particularly their thermal behavior. Resistance to various classes of chemicals for numerous synthetic resins and rubber derivatives are tabulated and discussed.—RPI.

5.4, 4.2, 2.2, 5.9

Endurance Tests with Rust Preventive Paints in Comparison with Red and White Lead Paints. F. Eisenstecken & H. Kickermann. PB. 70163, Frames 1484-1507; *Prev. Det. Abs.*, **5**, Lac 19 (1948).

Steel panels coated with various paint compositions were exposed to industrial and rural atmospheres for a period of 4 years. Some of the panels were sandblasted and others had rolled skin surfaces. Industrial atmospheres proved more corrosive than rural ones for rolled skin samples, but 50% of sandblasted samples was destroyed in both industrial and rural atmospheres. Lead paints were most resistant to natural weathering followed by Trix. Osmal and granite paints.—RPI.

5.4, 2.3

New Torch Licks Problem of Flame-Spraying Polythene. W. B. DeLong & E. V. Peterson. E. I. du Pont de Nemours & Co. *Chem. Eng.* **56**, No. 6, 123-125 (1949) June.

Way to coat steel with Polythene is solved with use of flame-spray gun which is described. Coatings are not porous, they adhere and retain all of Polythene's corrosion resistance. Discussion includes torch details, adhesion, modifiers, application technique and corrosion tests.—INCO.

5.4, 7.5, 4.3

Report Successful Method to Spray Polythene on Metals. *American Metal Market*, **56**, No. 119, 1 (1949) June 21.

The engineering research laboratory of the du Pont company has developed a successful method for the flame spraying of Polythene on metal surfaces. Because Polythene is usually inert and highly resistant to corrosion, it is particularly attractive as coatings for metal surfaces, such as tanks and drums, where corrosion is a factor. The surface is preheated to 400-500° F (204-260° C) and small quantities of finely powdered graphite or carbon black promote adhesion. Exposure of 300 days' duration with sulphuric, hydrochloric, and other acids

have shown no deterioration in coating properties or base metal attack.—ALL.

5.4

Protection of Aluminum Surfaces. *Surveyor* (England) (1948) Nov. 12. *Light Metals Bull.*, **11**, No. 4, 158 (1949).

British Paints, Ltd., in collaboration with the Northern Aluminum Co., Ltd., produced a special form of protection for the Hendon Junction Bridge, Sunderland. It is generally now agreed that paints containing lead are unsuitable for use as first coats for aluminum and light alloys because of the danger of interaction with the metal. British Paints, Ltd., has developed a special corrosion inhibiting primer for the purpose of keeping the metal surface in an excellent state of preservation, and at the same time creating a suitable surface for further coats of paint, either decorative or protective.

The priming coat was applied before erection and careful touching up was carried through by the painting contractors, James Robb and Son of Newcastle-on-Tyne and London, before applying the remainder of the paint. Particular attention was paid to the iron rivets and surrounding areas in view of the fact that aluminum was not used in riveting. "Mettal" aluminum paint and undercoating were then applied. The three paints included in this specification have been specially designed as integral parts of a complete "three coat treatment," and each in its turn assists in furnishing the aluminum with maximum protection.—ALL.

5.4

Mechanism of Pigmentation. H. Wagner. *Arch. Metall.*, **1**, 448-51 (1947). Brit. Abs. B-11, **1949**, 110.

Paint pigments may act electrochemically, but a review of recent investigations shows that such action can play only a minor part in protecting iron from corrosion, although it can be of value when the paint is aged. The important function of the pigment is to influence the structure of the paint film. —RPI.

5.4

Insecticide Paints with DDT. G. Salomone. *Ind. della Vernice*, **3**, No. 21, 2-4 (1949).

The insecticidal properties of systems including DDT (a) incorporated directly into paints, and (b) sprayed from white spirit solution on to paint films to give about the same concentration (2% in both cases) have been compared. Silicate, oil, alkyd and enamel type paints, and fly, cockroach and cabbage white butterfly test insects were used. Minute crystals of DDT could be observed under the microscope in the films of the silicate and alkyd paints of series (a), but not in the oil and enamel paint films. Even warm alcohol did not extract any toxic agent from these films. The percentage of flies, cockroaches and butterflies, respectively, killed after 24 hours in the test chamber was in series (a) 27, 13, 19; 18, 7—; 24, 9, 10; 11, 4, —; and in series (b) 73, 38, 75; 80, 45, —; 81, 48, 88; 82, 45—. Although the insecticidal properties of the paints in the (a) series were poor, they deteriorated still further on ageing of the paint film; after 16, 46 and 121 days ageing of the silicate and alkyd paints, the percentage of flies killed was, respectively, 21, 14, 5; 17, 9, 2.—RPI.

5.4

Hydraulic Binders in the Paint and Coatings Industry. H. Rabate. *Peint. Pig. Vernis*, 24, No. 9, 273-4 (1948).

An editorial concerning the use and action of hydraulic lime and hydraulic cement in anti-corrosive paints. A comparison is made with anti-corrosive pigments.—RPI.

5.4

"Araldit" Varnishing Resin for the Surface Protection of Metals. G. H. Ott. *Schweiz. Arch. angew. Wiss. Techn.*, 15, No. 1, 23-31 (1949) (in German).

The structure and synthesis of the "Araldit" group of synthetic resins are described. The results are presented of experiments on Araldit-985E in which the effects of various curing times in the range 20-160 min. and curing temp. in the range 160°-220° C on the properties of coatings 0.7 mm. thick, were studied. The Sward hardness was little affected by these variations in curing treatment, being about 82; the Erichsen ductility test gave a figure of about 9 mm. except with the lowest curing time and temp. Short curing times and low curing temp. yield a colorless film; longer times and higher temp. result in yellow, golden, and eventually golden-brown films. The protection against corrosion afforded by the resin was investigated by immersing coated specimens of iron and aluminum in various corrosive media (mainly organic) for times up to 30 days at 25° C. Slight attack was produced by 5% formic acid and by 5% acetic acid. +0.5% copper sulphate, but the other reagents did not attack the specimens. Some short-time tests were also carried out at temp. up to 100° C; in no case did any attack occur. Further tests on coated aluminum boxes and tooth-paste tubes are described. Applications of the resin are discussed. It can be dyed and pigmented.—MA.

5.4

Second Annual Guidebook-Directory Issue. *Organic Fin.*, 10, No. 4, 234 pp. (1949) Apr.

Short articles and other information on enameling and lacquering of metal and wood, including preparation of metals (steel, aluminum, magnesium, zinc, copper and brass) for painting; phosphate treatment; corrosion prevention; principles of vapor degreasing; properties of materials (resins, solvents, drying oils, plasticizers, pigments, etc.), used in organic finishes; finishing methods and equipment; testing and costing. The directory lists U. S. manufacturers, trade names, consultants, reference books, etc. There have been no great changes since the first annual issue (1948).—BNF.

5.4

New Aspects of Rustproofing. Arthur Minich. *Paint, Oil and Chem. Rev.*, 112, 42+ (1949) Apr. 14.

Discusses electrochemical aspects and limitations of rigid coatings. Describes different test methods used to evaluate a rustproofing agent known as "Nuodex Compound X-545"; and gives results of its use under various conditions.—BLR.

5.4

Red Lead Guards Against Rust on Famous Bridges. *Lead*, 17, No. 3, 2-3 (1949).

The new North State Street Bridge,

Chicago, now nearing completion, is protected with a red lead/linseed oil undercoat which is claimed to have a protective life of 8-10 years. This undercoat is used also on the Queensboro Bridge, New York, and on the Oakland Bay Bridge, San Francisco.—RPI.

5.4

The First Year of the Paint Research Project at New York University. M. Kronstein. I er Congres Tech. Internat. Ind. Peint., Paris, 1947, 232-9.

An account of the activities include the study of the effect of pretreating metals before applying organic coatings. For this purpose the changes in the magnetic and electrical resistance qualities of the metal were measured both before and after pretreatment. Surface profile measurements were also made. In the oils field it has been found possible to isolate solid polymerized oil substances directly from the liquid oil. These solid polymers are fluffy dry substances, insoluble in boiling toluene and incapable of forming coherent films. A discussion of the infrared spectra of the oil derivatives is included.—RPI.

5.4

Protective Coatings for Metals. R. Krause. Board of Trade, Ger. Div. FD. 262/48, Frames 1150-69.

A bibliography of German publications for 1941 on the protective coatings for metals which also appeared in B.I.O.S. Final Report No. 335.

5.4

Petroleum-Base Protective Coatings. Will H. Shearon, Jr., & A. J. Hoiberg. *Ind. & Eng. Chem.*, 41, No. 12, 2672-2679 (1949) Dec.

A brief history of the use of asphalt as a protective coating introduces the discussion of modern day protective coating manufacture from petroleum. Plan processes are described with a number of flow sheets and photographs of plant equipment. Rust preventives are divided into two classifications—non-drying types or slushing compounds and preventives which dry to a hard film. In addition, products may be classified according to their uses such as corrosion preventive, bearing compounds, greases and oils; metal conditioning compounds; solvent type preventives (outdoor); and solvent type rust preventives (indoor).

The article discusses the manufacture of oil type, semi-solid and solid types, and solvent type rust preventives with remarks on the application of each. Future prospects of a progressive coating manufacturer is discussed. References are made to the literature and processing equipment.

• Oil & Grease Coatings

5.5, 5.9, 2.3

Finishing Metals—Part II. Fred D. Johnson. *Can. Paint & Varnish Mag.*, 21, No. 10, 22 + (1947) Oct.

Osmosis is explained as being the principle of paint failure due to penetration of water into the paint film. If maximum resistance to the ravages of water is to be obtained in a finish, certain fundamental phenomena must be considered.

(1) The vehicle has the least resistance to water penetration if it dries by

oxidation or reaction with air. The poorest of this type are based on straight linseed oil. Alkyd finishes allow only two thirds of the penetration of linseed oil, and phenolics allow about half the penetration of alkyds. Baked finishes are better than any which dry by oxidation, and the newer synthetic lacquers based on vinyl resins appear to be the best available.

(2) Pigmented finishes are almost always better moisture barriers than unpigmented finishes. Some pigments improve this property by as much as 100%. On the other hand, pigmentation appears to lower rather than improve the water resistance of some of the vinyl finishes.

(3) Osmosis causes film breakdown most readily in fresh water or extreme conditions of moisture condensation. Electroendosmosis acts rapidly and violently in salt water where the film is ruptured and the metal is allowed to freely corrode at one spot.

(4) Passivation is necessary for maximum water resistance. This process leaves a surface coated with a thin film of oxidized metal or metallic salt which cannot set up electrical conditions when the coating is penetrated by water. Thus corrosion of the metal and subsequent breakdown of the adhesion of the protective covering is prevented. Passivating primers, such as zinc chromate, should be used before applying the finish coat.

The conclusions are based on the results of earlier experiments in which steel, duraluminum, zinc and glass were coated with zinc chromate primer followed by a gray, low-gloss alkyd enamel. The thickness was carefully controlled. Six immersion baths were prepared, one of distilled water and the others containing from 0.758% to 3.790% salt solution.—PDA.

5.5

Was Coating Protects Street Lighting Reflectors. W. Skove & A. Nichols. *Electric Light and Power*, 26, 98, 100 (1948) Dec. *Metals Rev.*, 22, 33 (1949) Jan.

Tests under severe atmospheric conditions demonstrate that application of wax coating to polished surfaces of aluminum street-lighting reflectors permits periodic cleaning by wiping with a dry cloth to restore reflection efficiency.—ALL.

5.5

Rust Preventives Help Maintain Steel Structures. J. G. Surchek, Dearborn Chemical Co. *Iron & Steel Eng.*, 26, No. 5, 82-85 (1949) May.

Petroleum base coatings are effective in preventing corrosion because they are relatively waterproof, and stick to and with the metal to be protected. The role played by the inhibitor in organic films is described. The application of these heavy waxes to both exterior and interior of steel and cast iron pipe, the protection of gas holders, and their use in railroad and marine equipment are discussed.—INCO.

• Packaging

5.6

New Way of Preventing Corrosion. T. Williams. *Canadian Chem. and Proc. Ind.* (Canada) 33, No. 5, 536 (1949) June.

In collaboration with Britain's Rub-

ber Producers' Research Association, the British Department of Scientific and Industrial Research has undertaken considerable work on sodium benzoate in wrappings, and as a preventive for the corrosion of metals. These experiments have led to the making of rubber latex impregnated with sodium benzoate. This material has a double protective action, excluding damp air and corrosive vapors, and also reinforcing the normal action of wrapping, even replacing it if the wrapping breaks. Articles to be protected may be immersed in the benzoate latex or sprayed. The latex dries quickly to a thin, tough coating completely covering the object. The coating does not adhere to the metal, and can be stripped off easily. Benzoate latex maintains metals bright and untarnished after long exposure under severe conditions, whereas rusting soon occurs under the same conditions when ordinary latex is employed for the same purpose. Benzoate latex is especially useful to protect machined metal parts when in storage or transit.—ALL.

5.6

Some Aspects of Packaging in Metal Containers. R. K. Sanders. *Chem. & Ind.,* 151-155 (1949) Mar 5.

Discusses above under headings of leakage, mechanical strength, corrosion, application of coatings, and design for ease of opening.—BLR.

• Treatment of Medium

5.7

Effect of pH-Value and Nature of Attacking Solution on Intercrystalline and Stress Corrosion of Aluminum-Magnesium Alloys. H. Vosskurler. *Archiv fur Metallkund,* Germany, **3,** 28-33 (1949) Jan. *Metals Rev.,* **22,** No. 6, 30 (1949) June.—ALL.

• Inhibitors

5.8, 3.6, 1.8, 4.3

Hydrogen Overpotential and the Partial Inhibition of the Corrosion of Iron. J. O'M. Bockris and B. E. Conway. *J. Phys. & Colloid Chem.,* **53,** 527-539 (1949) Apr.

Action of inhibitors in pickling baths is considered to be due to increase in hydrogen activation over-potential on iron, or to mechanical protection by adsorbed film. Present paper seeks to distinguish between those two views, and reports experimental measurements, concluding that the mechanism of the inhibition of corrosion is by means of a direct effect on the hydrogen activation potential and not by mechanical protection through an adsorbed film.—INCO.

5.8, 4.4, 2.3, 7.1, 8.9

Oxidation of Lubricating Oils—Diakyl Selenides as Inhibitors. G. H. Denison and P. C. Condit, Calif. Res. Corp. *Ind. & Eng. Chem.,* **41,** No. 5, 944-948 (1949) May.

Various diakyl selenides were prepared and shown more effective inhibitors of oil oxidation than corresponding sulfides. Diakyls are more active than diaryl compounds. Strip corrosion and engine test data bear out inhibitory value of diakyl selenides as determined

by oxidation tests and, in addition, show selenides are free from deleterious oxidation products such as are encountered with sulfur compounds. Formation of little gum or sludge by selenide inhibited oils is explained by fact that oxidation products of selenide are thermally decomposed to non-gum forming products instead of being further oxidized to strongly acidic materials which could, as do sulfonic acids, accentuate gum formation.—INCO.

5.8, 8.9

Alox 350, a Polar Type Rust Inhibitor for Oils. *Chem. Eng. News,* **27,** 1092-3 (1949) Apr. 11.

Contains mostly methyl esters of high molecular weight organic acids. Other oxygenated hydrocarbons, including relatively small amounts of free, high molecular weight, non-corrosive organic acids, are also contained in this Alox Corp. product. The solid is also available as a 10% concentrate in a light naphthenic oil called Alox 361. Either form is uniform and stable. Hydraulic, slushing, automotive and gear oils which contain a maximum of 1% of Alox 350 have maintained corrosion-free systems over many years of service. In lube oils Alox 350 gives decrease in wear of moving parts and freedom from corrosion even after long periods of operation, including idle periods.

5.8, 4.6, 5.7, 2.3, 1.8

Corrosion Inhibitors in Recirculating Water Systems. M. Darrin, Mutual Chem. Co. of America. *Can. Chem. Proc. Inds.,* **33,** No. 6, 512-516 (1949) June.

Inhibitors which function through anodic polarization are discussed. Discussion includes adjusting pH, preventing harmful deposits, removal of corrosion constituents, cathodic polarization, anodic passivation, amount of chromate required, corrosion stimulation and experimental data.—INCO.

5.8, 6.2

Passivation of Aluminum. A. Baevens. *Ingenieur's Grav.* (Germany) **60,** No. 11, MK32-34 (1948). *Brit. Abs.* **(1949 B. I.)** 75 (1949) Jan.—ALL.

5.8

Sodium Nitrite as an inhibitor Against the Attack of Sea Water on Steel. Part I—The Influence fo Sodium Nitrite on the Area and Intensity of Attack. D. Wyllie and G. C. N. Cheesman. *J. Soc. Chem. Ind.,* **68,** No. 6, 165-168 (1949) June.

Prevention by sodium nitrite of attack of sea water on steel was studied in two ways. Observation of extent and nature of corrosion of mild steel specimens partially immersed in sea water containing nitrite. Measurement of corrosion currents using a divided cell. Appearance of a widespread brown discoloration on steel at higher nitrite concentrations is discussed and a catalytic mechanism is suggested for inhibiting action of nitrite. Effect of mixing phosphates and nitrite is reported. 9 references.—INCO.

5.8

Theory of Corrosion Inhibitor Action. H. J. McDonald, G. A. Marsh & R. D. Misch. U. S. Office of Naval Research Contract N7-onr-329; *Prev. Det. Abs.,* **5,** Met. 240 (1948).

Inhibitor evaluation, using the pulse polarizer indicated that the dissolution

rate of metals could be quantitatively predicted from polarization data. From this data it is also possible to form a scale of inhibitor action similar to the scale of H ion concentration.—RPI.

5.8

The Role of Inhibitor Films in Electrode Processes, Final Report. Hugh J. McDonald, Glenn A. Marsh, Robert D. Misch and R. B. Bernstein, Illinois Institute of Technology, Chicago, Corrosion Research Lab. U. S. Office of Naval Research, Contract N7-onr-329, Task Order 1 (1948) Aug.

Two instruments were developed to evaluate inhibitors by determining their effect on the electrode polarization of metals. The pulse polarizer, utilizing a single pulse of current, furnished data which were useful in differentiating and establishing a scale of inhibitor effectiveness, although the complete interpretation of the polarization curve was often impossible. Papers based on this work have been published elsewhere. The second instrument, the scope polarizer, though theoretically more satisfactory for recording the common potential—current density curves, was not sufficiently sensitive to differentiate and classify inhibitors.

To clarify the mechanism of inhibitor effectiveness and the factors involved in electrode polarization, a study was made of the influence of surface films on the electrodeposition of hydrogen on palladium. The transmission of hydrogen through a palladium cathode depends largely on the nature of the adsorbed surface film. With electro-deposited "metallic films" a steady reduction in the percentage of transmission was always observed. Mercuric and cupric ions severely reduced the transmission; ammonium ion had little effect. With organic films an increase in transmission was also obtained, depending on adsorption behavior of the compound and the thickness of the film. Weakly adsorbed organic films of ethanol, butylamine, and gelatin had only slight effects. Strongly adsorbed compounds, such as thiourea, diisopropylthiourea, 1-iodobutane, styrene, and benzyl sulfide, produced an increase in the transmission when present in low concentration as in a thin film; when added in excess, however, most of these compounds decreased the transmission depending upon the film thickness.

Two cathodic electrode mechanisms seem possible with organic films: In thin films of strongly adsorbed compounds, protons may diffuse through the film to be discharged at the palladium surface. In thick films of all types, electron transfer and hydrogen discharge at a distance from the metal lattice may be the rate-limiting process. A transition from the first to the second mechanism was observed in three films of increasing thickness.

In making these determinations the transmission of a clean palladium electrode was first determined. Then the change in transmission was observed after adding various amounts of the substance under consideration. In the case of metallic films, both copper and mercury were added to the solution as salts and electrodeposited. Organic films were produced by adsorption from solution and direct deposition on the dry electrode. Changes of $\pm 1\%$ in the transmission resulting from the influence of surface films could be readily detected

since the permeability measurements were carried out immediately following the determination of the transmission of the clean electrode.—PDA.

5.8
Mechanism of the Action of Inhibitors During the Dissolution of Iron by Acids. (In Russian.) V. A. Kuznetsov and Z. A. Iofa. *J. of Physical Chem.* (U.S.S.R.), **21**, No. 2, 201-214 (1947).

Influence of a series of organic compounds or the rate of solution of pure iron in hydrochloric acid was investigated. Results are indicated by polarization curves. 29 ref.—BLR.

• Surface Treatment

5.9, 3.5, 3.4, 2.3
A Practical Method of Electrolytic Polishing for Steels and Chromium for Micrographic Examination. P. A. Jacquet. *Compt. Rend.*, **227**, 556-558 (1948); *J. Iron Steel Inst.* (Abs.), **161**, 76 (1949).

The difficulties and dangers in the use of the anhydrous solution of perchloric acid and acetic anhydride previously proposed by Rocquet and J. are avoided with the present solution in which the acetic anhydride is replaced by the acid and only very little perchloric acid is used. A suitable mixture is: 1000 cc of pure crystallizable acetic acid and 50 cc of 60-60% perchloric acid (sp. gr. 1.59-1.61). The liquids mix at once without liberating heat. The reagent works satisfactorily even when much contaminated with dissolved iron after long use. Best polishing results are obtained with a c.d. between 12 and 30 amp./dm.² with a potential of 30-50 V. for specimens 1-15 cm.² in area and a plane cathode 50 cm.² in area placed at a distance of a few centimeters in front of the surface to be polished. The relatively high voltage can be reduced by adding a very little distilled water (0.5-1.5%) or by using a cylindrical cathode surrounding the anode. Solutions containing acetic plus perchloric ions attack iron chemically without an applied current, the more so as the temp. rises, so, in order to avoid staining the specimen is agitated for a few seconds in a dilute aqueous solution of hydrofluoric acid immediately on removal from the polishing bath. This treatment also causes differential coloring, showing up ferrite grains and bainitic, sorbitic, and pearlitic structures, as well as the traces of plastic deformation and veining.—MA.

5.9
Burdett Incorporates Rust-Proofing Treatment Into Its Burn-Off Process. *Ind. Heating*, **14**, 986, 988 (1947) June.

New Burdett Burn-Off Rust-Proofing process consists primarily of the proper placing of gas-fired infrared burners in relation to the work. This process is claimed not only to remove grease and similar film, but simultaneously to produce a blue surface on the metal that is extremely rust resistant.—BLR.

5.9, 6.2
Composition of the MBV Layer and Change in Its Properties on Ageing and Heating. Helling. PB. 70016, Frames 5425-32; *Prev. Det. Abs.*, **5**, Met. 173 (1948).

The influence of structural changes, of ageing and heating on, interalia, the absorptive properties for paint, of the MBV layer (on aluminum) is studied.—RPI.

5.9, 6.2
Thickness of the MBV Layer as a Function of Length of Treatment. Helling. PB. 70016, Frames 5451-9; *Prev. Det. Abs.*, **5**, Met. 160-1 (1948).

A study of the variables influencing structure of the MBV layer (on aluminum) and its suitability as a surface for lacquering.—RPI.

5.9, 6.2
Pure Aluminum Treated with MBV. Geller & Geier. PB. 70016, Frames 6622-37; *Prev. Det. Abs.*, **6**, Met. 28 (1949).

Corrosion tests made on coatings carried out by various modifications of the MBV treatment varied widely. In some corrosive solutions the protective effect seemed to depend upon the thickness rather than the density of the coating and in others results were dependent on the density.—RPI.

5.9, 6.3
Surface Oxide Removal Important in Final Processing of Aluminum. A. E. Durkin, General Electric Co., Thomson Laboratory, Lynn, Mass. *Mat. & Meth.*, **27**, No. 4, 82-85 (1948) Apr.

Maximum weathering resistance, adhesion, and uniformity of inorganic coatings on aluminum, as well as uniformity and quality of welds can be insured only when parts have been properly cleaned and deoxidized. The importance of good rinsing facilities in these operations cannot be over-emphasized. In setting up a process that includes the use of agents for removing surface oxides, it is important to consider the material to be cleaned, the number of tanks involved, the controls necessary to maintain concentrations and temperatures and any special equipment that may be required.

Extended tests with various cleaners and oxide removers resulted in the following conclusions:

(1) With sodium hydroxide the surface resistance values of the cleaned aluminum are neither uniform nor sufficiently low, the immersion time is critical, and close control of the concentration and temperature is required.

(2) With chrome-sulfuric acid the surface resistance values are low, the immersion time is critical, and the allowable time of exposure before reoxidization is short.

(3) With chrome-phosphoric acid surface uniformity is not obtained immediately after treatment as it is with (2).

(4) With hydrofluoric acid initial resistance values are low but the immersion time is prohibitively critical. An oven treatment of about 10 seconds resulted in etching and high surface resistance.

(5) With hydrofluosilicic acid, surface resistance values are not sufficiently low even when tested with a wetting agent and reoxidization of the surface is rapid.

(6) With a cold-dilute sulfuric acid type deoxidizer, resistance values are low and oxidation is retarded, whereas with two other compounds of the hot-dilute acid type the results are unsatisfactory.

All oxide removers were tested on 2SH, 2SO, 3S and 14ST panels. Before testing for surface resistance, the materials were emulsion-dipped, hot rinsed, spray rinsed, treated with inhibited cleaner, rinsed, spray rinsed, treated with oxide remover, again rinsed and finally dried. Surface resistance was deter-

mined by passing a current of 10 a. through a weld line held under 500 or 1000-lb. pressure and reading the voltage from a volt-ohmmeter.—PDA.

5.9, 6.3
Cleaning with Framanol: A New Process for the Preparation of Surfaces and for the Protection of Aluminum. Jean Frasch. *Rev. Aluminum*, **142**, 84-89 (1948).

For the cleaning of aluminum surfaces, especially for welding, and as a step in final protection there exist many solutions: some are better for a given alloy than others. F. attempted to evolve a cleaning solution which would both degrease and clean, which would be applicable to all alloys, would operate at room temperature, and could also be applied locally to large pieces by brushing or sponging. The result of this attempt was the evolution of Framanol, a complex solution of phosphates of chromium and of triethanolamine. Test data on specimens of aluminum alloy A-U4G are given, in which Framanol is compared with caustic soda, nitric acid, fluosilicic acid and sulfuric-chromic acid. It is claimed that Framanol is far superior to these.—MA.

5.9, 4.1, 4.6, 7.3, 2.3
Improved Corrosion Resistance and Paint Adherence. *Die Casting*, **7**, No. 4, 59-60 (1949) April.

Iridite, a chromate finish, developed to permit use of zinc die castings in tropical climates or salt atmospheres gives a good paint base while improving surface characteristics. Available in two colors, the olive drab is useful in water and salt corrosion atmospheres, such as water pumps for washing machines, refrigerators and refrigerated vending machines, or as a base for paint, while the bronze type is applied successfully on die castings coming into contact with mixtures of gasoline and water such as automobile pumps. In a continuous two year humidity test on a cycle of 6 hours at 120° F and 50% relative humidity only a 10% reduction in paint adherence was recorded and there was no evidence of corrosion.—INCO.

5.9, 6.1, 6.2
Chemical Surface Treatments for Metals I & II. A. E. Durkin. *Tool Engineer*, **22**, 2225 (1949) April; ibid, No. 5, 34-36 (1949) May.

I. Discusses alkaline cleaning, vapor degreasing, rust and scale removers, black oxide treatments of steel and phosphate coatings. This installment deals only with general principles and equipment and application to steels. (To be concluded.)—BLR.

II. Electrolytic and chemical coatings are produced on aluminum to obtain maximum corrosion resistance. The most common electrolytic coatings are those produced in sulfuric and chromic acid baths. Thickness of film formed is between 0.0001 and 0.001 in., with an average of about 0.0003 in. A comparison of anodic processes is tabulated. The common chemical treatments for aluminum are the chromic acid type, phosphates and alkaline dichromates. A comparison of the coatings is given with the corrosion resistance produced by each. A suitable coating for magnesium which will match in corrosion protection the films formed on aluminum is not yet available.—ALL.

5.9, 6.2

Surface Finishing and Protection of Magnesium Alloys. H. K. DeLong, Dow Chem. Co. Paper before Magnesium Assn. *Modern Metals*, **5**, No. 6, 26-29 (1949) July.

An over all review of methods used in finishing magnesium which includes surface conversion coatings by chemical dipping and anodic oxidation, painting and the new electroplating process. Discussion includes chemical treatment, bright chromic acid pickle, caustic anodize, borate-silicate anodic treatment, painting, primers, finish coats, electroplating, plating methods, corrosion resistance and adhesion.—INCO.

5.9, 6.2

Preparation of Metal Surfaces Preparatory to Finishing. V. M. Darsey. *Am. Paint J.*, **33**, No 12, 46+ (1948).

The methods of surface-cleaning nickel are (1) methods which do not materially change the surface characteristics of the metal; (2) methods which mechanically or chemically alter the surface; and (3) methods which convert the surface to a non-metallic coating, e.g., phosphate coating, thereby inhibiting corrosion and increasing the adhesion of applied organic finishes.—RPI.

5.9, 1.2

Control of Surface Finish Improve Quality, Cuts Cost. H. R. Clauser. Materials and Methods, Editorial Staff. *Mat. & Meth.*, **28**, No. 4, 74-77 (1948) Oct.

The quality of a surface finish is an important factor in the performance and life of many metal parts. In moving parts such performance characteristics as abrasion, lubrication, fit, sliding action, bearing qualities, and leakage may be improved or hampered by the particular surface finish selected. Fatigue strength, notch sensitivity, load carrying capacity, heat transmission, and optical properties are some of the mechanical and physical properties that can be affected. In addition, if the part is to be plated or painted, the surface can influence the adhesion and appearance of the coating.

Because costs are directly related to the degree of finish it is poor economy to make a surface smoother than is required for the proper functioning and satisfactory service life of the product. Where lay, or scratch pattern, and waviness of the finish are not particularly important it is often possible to reduce costs by merely specifying the allowed roughness, and then permitting the production department to obtain that roughness by the most efficient method. But when lay and/or waviness must be considered, it is usually not enough to specify just the limit of roughness, because waviness and lay vary according to the processing method used.—PDA.

5.9, 6.2, 4.6, 8.7

Brunak, The New Anti-Oxidation Surface Treatment for Aluminum. Michael H. Bruno and Paul J. Hartsuch, Bruno Lithographic Technical Foundation, New York, N. Y., Research Dept. *Modern Lithography*, **16**, No. 4, 51-53 (1948).

In Midwestern localities, aluminum plates used in lithography often develop a pitting type of corrosion believed to be associated with the local water supply. This corrosion can be prevented or greatly retarded by the Brunak process which consists of bathing the plates for

1.5 —3 min. in a solution containing 3 fl. oz. 48% hydrofluoric acid, 27 oz. ammonium dichromate, and 3 gal. water. The treated plate has a light tan color. Operating directions are given in the report.

Brunak-treated sample plates which had been immersed for 6 months in Chicago tapwater were still largely free from oxidation, whereas untreated aluminum plates were badly corroded.

The making of an albumin or a deepetch plate on Brunak-treated aluminum is only slightly different from the usual procedure. The principal difference is the removal of the powdery material before coating the plate, and the pre-etching of the albumin plates.—PDA.

MATERIALS OF CONSTRUCTION

• Non-Ferrous Metals

6.2

Aluminum Alloy Wire. F. H. Slade. *Machinery Lloyd*, England, **20**, No. 24, 104-108 (1948) Nov. 24; *Hiduminium Abs. Bull.*, Eng., **17**, No. 11, 12, 208 (1948) Nov.-Dec.

Advantages of aluminum as a wire material are 1) high corrosion resistance, 2) light weight facilitates handling and transport, 3) high electrical conductivity makes it suitable for electrical transmission lines, 4) a range of colors can be produced by color anodizing. An aluminum-magnesium alloy is the most generally used for drawing to wire, such an alloy being able to withstand 70% reduction in area between annealings and a 30% reduction between passes. Thus it is possible to reduce a fully annealed wire rod of 5/16-inch diameter to 0.1-inch without intermediate annealing. Conventional wire drawing equipment is used and both tungsten carbide and diamond may be used for dies, the former for drawing down to about 0.0265-inch diameter and the latter for smaller sizes. Drawing speed is not critical providing the wire temperature is kept reasonably low. Applications of aluminum wire apart from electrical purposes are mainly for fencing, agricultural baskets, haulage ropes and cables, baling wire, poultry netting and a wide variety of domestic appliances particularly kitchen equipment.—ALL.

6.3

Moisture and Vacuum Proof Case for Electrical Structural Elements, Especially for Electric Condensers Made from Artificial Thermo-plastics. Nurmberger, Schraubenfabrik und Elktrowerk. PB. 70093, Frames 3077-82; *Prev. Det. Abs.*, **5**, E 21 (1948).

Moisture and vacuum-proof cases for electrical condensers can be pressed, cast, or die-cast from polyurethane and similar thermo-plastic materials. They may be further waterproofed by coating them with polybutylene or similar lacquers or adhesives. The leads are cast, pressed, or die-cast simultaneously with the case in such a way that a considerable lead length is embedded in the top or the bottom of the case, parallel with the surface. The remainder is bent vertically into interior of the case.—RPI.

6.2

New Magnesium Alloys Offer Superior Properties. Kenneth Rose, Materials and Methods, Editorial Staff. *Mat. & Meth.*, **28**, No. 1, 66-69 (1948) July.

The composition and mechanical properties of alloy ZK60 and of magnesium-cerium alloys with about a 5% mixture of cerium and other rare earths are given.

ZK60 consists of $5.5 \pm 0.5\%$ Zinc, $0.50 — 0.75\%$ zirconium, and the balance magnesium. The principal effect of the zirconium is to produce and maintain a fine grain size, which results in good strength properties and toughness, and to reduce the iron content to an extremely low limit improving the weathering resistance of the composition.

ZK60 has outstanding impact toughness and compares favorably in fatigue strength with other high strength magnesium alloys. It tarnishes more readily, because of its high zinc content, but is amenable to the same surface protective treatment as magnesium alloys in general. The creep strength of zirconium-containing magnesium alloys is slightly lower than that of other high-strength magnesium extrusion alloys, but shear and bearing properties are about the same. The ZK60 has limited weldability and should be joined by riveting rather than welding. The alloy has been used successfully in several types of experimental wings and for aircraft floor beams required to withstand high stresses.

The most successful magnesium-cerium alloy is EM51, containing 5% Mischmetal (50% cerium, 50% other rare earths), 1.2% manganese, and the balance magnesium. It can be either cast or wrought, but for casting a 6% content of mixed rare earths is recommended.

Maximum properties for high-temperature use are obtained by solution heat treatment for 4 hrs. at 1050° F., followed by aging for 16 hrs. at 400° F. Compared with other magnesium alloys having high strengths at elevated temperatures, the improvement of the magnesium-cerium compositions becomes large at 500-600° C. At about 600° C., EM51 reaches the creep resistance of aluminum alloys. Cerium-containing magnesium alloys are readily weldable and exhibit good machinability. The addition of cerium to magnesium alloys is expected to extend their working range to 300° F. higher than present limits.—PDA.

6.2

Uncorrodible Metal. *Steel*, **124**, No. 18, 81 (1949) May 2.

Titanium metal is practically unaffected by exposure to sea water or marine atmosphere according to test data obtained by Remington Arms Co., Inc., Bridgeport, Conn. Tests indicated that none of the standard metals approached the corrosion resistant properties of titanium, and that wet chlorine gas, hot chromic acid and hot ferric chloride solutions are not corrosive to it.—ALL.

6.2

Titanium Metal Produced by Arc Melting; Strength Corrosion Compared to 18-8. Cross, H. C. *Metals Rev.*, **22**, No 4, 17 (1949) Apr.

A graphic picture of the metallurgy of titanium and titanium-base alloys was presented at a meeting of the ASM by H. C. Cross of the Battelle Memorial Institute. Several methods of producing metallic titanium pure enough to be ductile at room temperature are available,

including the De Boer process, the Kroll process, and a process employed by the Bureau of Mines using powder metallurgy techniques. A special arc melting furnace has been developed at Battelle for direct melting of titanium powder or sponge using a water-jacketed copper crucible, a tungsten-tipped water-cooled electrode, and a pure argon atmosphere. Iodide-titanium, which is of very high purity and only 40,000 psi in tensile strength, is an admirable base material for alloy studies. On a strength basis, unalloyed titanium is superior to magnesium and aluminum alloys, SAE 1015 steel, and annealed 18-8 Cr-Ni steel. Corrosion tests indicate that titanium is at least equivalent to 18-8 for general marine applications. Unalloyed titanium appears to be more difficult to machine than aluminum and copper-base alloys, plain carbon steels of similar strength, and 18-8, but easier than the Hadfield-type manganese steels. In preliminary tests titanium has shown good welding characteristics.—ALL.

EQUIPMENT

• Engines

7.1, 4.3
Study Corrosion in Rocket Engines. *Aviation Week*, **51**, 25 (1949) July 4.

Eng. Division of AMC and Reaction Motors, Inc., are investigating causes of corrosion in rocket engines. One cause of corrosion was found to be carbon tetrachloride which is used in cleaning in the field. Fuel pockets is another cause. Nitrogen flushing after each firing is proposed.—INCO.

7.1
Diesel Wear Related to Percent of Sulfur in Fuel. *SAE J.*, **55**, 70 (1947) July.

Digest of "Effects of Nitrogen and Sulfur Content of Fuels on Rate of Wear in Diesel Engines," by C. C. Moore and W. L. Kent.

Outlines result of a study of the effects of sulfur, nitrogen, and naphthenic acid on the rate of wear in Diesel engines.—BLR.

7.1
Piston Ring and Cylinder Wear in Diesel Engines. J. W. Pennington, Caterpillar Tractor Co. *Diesel Prog.*, **15**, No. 3, 46-48 (1949) Mar.

Corrosion is listed among processes causing cylinder and piston ring wear. Ricardo is mentioned as having given one of the first and best discussions of wear caused by corrosion in engines in 1933. Principal factors influencing corrosion in Diesel engines seem to be sulfur in the fuel and low temperature operation. Sulfur can cause high wear rates under both high and low temperature conditions. Low temperature operation accelerates wear, with and without sulfur. Graphs and diagrams are given which illustrate 1) cylinder wear patterns using 1% S fuel, the same lubriating oil, and a jacket temperature of 100° F, 2) temperature and wear pattern obtained when the piston is reversed, 3) wear pattern obtained at a high jacket temperature with a high S fuel, but with a different lubricating oil, and 4) the effects of the lubricating oil on the wear obtained with a high sulfur fuel. The results of these tests are compared and explained. Cast iron piston rings and liners were used in the investigation.—INCO.

7.1, 5.8, 2.2, 2.3
Corrosion of Turbine Journals. S. E. Bowrey. *Trans. Inst. Marine Eng.*, **61**, 57-65 (1949) Apr.; *J. Am. Soc. Naval Eng.*, **61**, No. 3, 664-682 (1949) Aug.

Corrosion inhibiting oils and the proposed water soluble inhibitor, sodium-nitrite are considered. Discussion includes account of laboratory investigations and sea trials of sodium nitrite with details of successful applications of proposals to case of a ship where gearing was already in an advanced state of corrosion.—INCO.

7.1, 3.6, 5.8, 5.7, 3.4, 3.5
The Causes and Prevention of Corrosion in Industrial Type Steam Turbines. *Allen Eng. R.*, **1949**, No. 22, 5-11.

Report of investigation of typical cases of corrosion, made in the laboratories of W. H. Allen and Co., Ltd., together with information from interrogation of users of turbines. It included consideration of electrolytic attack, influence of electromagnetic field, use of inhibitors, use of graphite injection, leakage during standing, occurrence of deposited salts associated with corrosion, methods of remedying deposition and standing attack. Discussion of the nature of the attack (erosion or corrosion-erosion) and of remedy against attack during running is given. Two distinct types of attack were found to cause damage in industrial steam turbines: attack during standing, due to combined deposition of salts during running and steam leakage when shut down; and attack during running, due to water impingement.—INCO.

• Valves and Pipes

7.2
Aluminum Valve Construction. R. McFarland. *Corrosion*, **5**, No. 1, 37 (1949).

A number of wrought and cast aluminum alloys have given a satisfactory performance in the construction of valves. They may be protected from corrosion by means of stoved phenolic resin coatings.—RPI.

7.2
Stainless Steel Piping; II—Selection of Pipe Joints; III—Fabrication by Welding. J. D. Mattimore. *Heat, Piping & Air Cond.*, **19**, 84-7 (1947); ibid, 12:73-8 (1947) Dec.

II. Unions which are slipped on the pipe end and soldered or brazed to it are recommended for sanitary piping. Galvanic corrosion and concentration cell corrosion are discussed. III. The necessary procedure for preparation of the piping for welding, welding and heat treatment after welding are discussed.—RA.

7.2
Aluminum Pipe Test. R. L. Bullock. *Corrosion*, **4**, No. 10, 505-506 (1948) Oct.

Aluminum pipe with welded joints every 40 feet is being tried for carrying crude oils. Internal and soil corrosion are being investigated.—BNF.
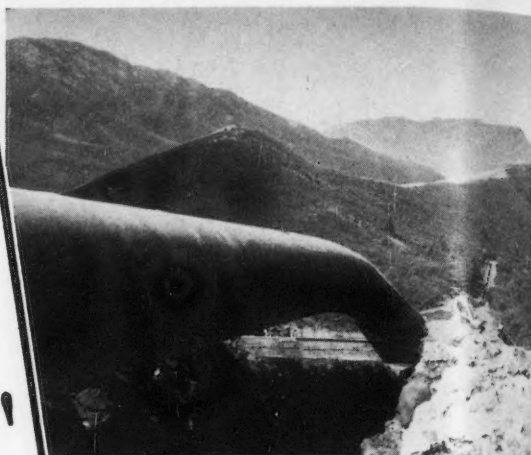
• Pumps and Compressors

7.3
Corrosion Problems in Water Wells. T. E. Larson. *Corrosion*, **5**, No. 1, 27-31 (1949) Jan.

In the construction of turbine pumps, combinations of copper bearing metals

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are frequently used in conjunction with cast-iron or steel. At points where these metals are exposed current will flow and the presence of water with a high mineral content will facilitate its flow. The painting of the copper-bearing cathode will impede the flow of current and prevent serious attack on the iron anode.—RPI.

7.3, 6.1, 4.6, 4.3, 3.5
Boundary Flow in the Diffuser of a High-Pressure Boiler Feed Pump. J. J. Holba. *Maschinenbau and Warmewirtschaft*, **3**, No. 11, 165-9 (1948) Nov.; *Eng. Dig.*, **10**, No. 4, 118-20 (1949) Apr.

Investigations were conducted to determine causes for erosion in diffuser of boiler feed pump by streamlines of boundary flow and at regular distances from the leading edges of the diffuser vanes. Observations indicated severe corrosion on cast iron and cast steel feed pumps. Collapse of vapor pockets, reinforced by acidity of feed-water, is suggested as cause of cavitation. Feasible solution seems to be diffusers manufactured from one integral casting.